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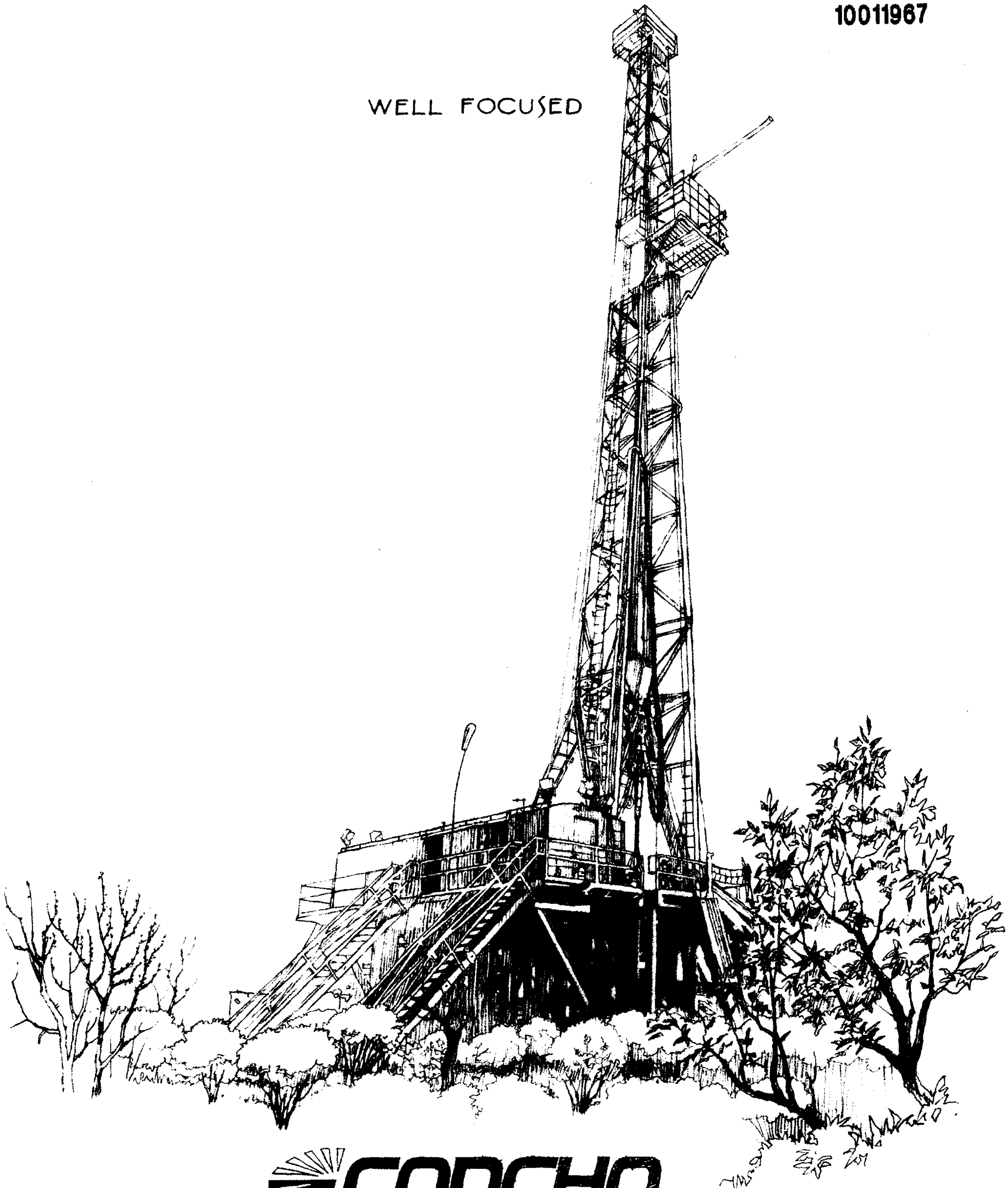
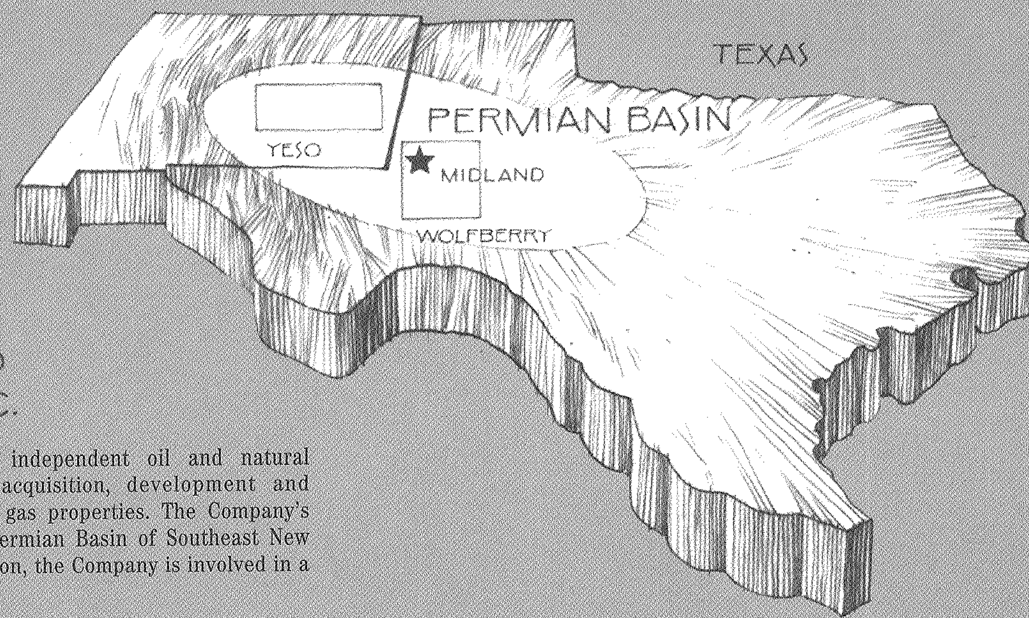


CONCHO

2009 ANNUAL REPORT



ABOUT CONCHO RESOURCES INC.

Concho Resources Inc. is an independent oil and natural gas company engaged in the acquisition, development and exploration of oil and natural gas properties. The Company's operations are focused in the Permian Basin of Southeast New Mexico and West Texas. In addition, the Company is involved in a number of emerging plays.

FINANCIAL HIGHLIGHTS

(DOLLARS IN THOUSANDS)	2009	2008	2007	2006
Production (MMBoe)	10.9	7.1	5.0	3.9
Oil Sales	$ 425,361	$ 390,945	$ 195,596	$ 131,773
Natural Gas Sales	119,086	142,844	98,737	66,517
Total Operating Revenues	544,447	533,789	294,333	198,290
Operating Costs and Expenses	(546,275)	(65,395)	(218,396)	(134,862)
Other Expenses	(28,706)	(27,607)	(34,558)	(29,381)
Income (Loss) Before Income Taxes	(30,534)	440,787	41,379	34,047
Income Tax (Expenses) Benefit	20,732	(162,085)	(16,019)	(14,379)
Net Income (Loss)	$ (9,802)	$ 278,702	$ 25,360	$ 19,668
EBITDAX	$ 475,094	$ 402,080	$ 217,760	$ 149,077
Proved Reserves (MMBoe)	211.5	137.3	91.0	77.8

TO OUR SHAREHOLDERS

Last year was a challenging year for the economy as a whole and for our industry in particular, which experienced commodity prices that fell to a low of $33.00 per barrel and $2.50 per Mcf as a result of the economic crisis. This sent a shock throughout the industry and resulted in the stacking of more than 1,300 rigs in North America.

Now that we are in a position to review our 2009 performance, I'm pleased to report that Concho not only survived the crisis, but the Company excelled, which demonstrates the strength of our assets and our team. It also reminds us that our industry has a history of price volatility and risk, and that the companies who survive and prosper are those that are capitalized and managed in a way to be profitable in both high and low commodity price environments.

The performance of Concho during 2009 further demonstrated our ability to grow while staying within cash flow. In light of the precipitous drop in commodity prices, our initial 2009 capital budget of $500 million announced in November 2008 was reduced in January 2009 to $300 million and we cut our operated rig count from seventeen to nine as we worked to keep our capital spending consistent with our anticipated cash flow for the year. As commodity prices began to recover later in the year and we became more confident in sustained higher commodity prices, we increased our capital budget to $400 million in August 2009 and started adding back rigs. As a result of increased drilling efficiency and reduced service costs, we were able to complete all of the capital projects in our initial capital plan while spending only $400 million, which was within our cash flow for the year and $100 million less than originally budgeted for those capital projects. Perhaps most impressive is the fact that despite this volatility in our capital budget caused by our desire to spend within cash flow, the Company was able to grow our production organically 34% during the year. In addition to the production growth generated by our capital program, we are also pleased that our reserves grew 54% at a very competitive all-in finding cost. This type of performance is a reflection of the quality of our assets and is the reason that our stock price outperformed our peers.

Additionally, we were pleased to announce in December the closing of two acquisitions in the Wolfberry play of the Texas Permian. Both of these transactions are consistent with our growth strategy, are strategically located in the heart of the play, increase our inventory of drilling locations, and will add to the trajectory of our production growth.

To position our capital structure for the volatility inherent in our business, and to prepare us for future growth, we raised capital recently through both a public bond offering in the fall of 2009 and a public offering of equity in early 2010. Today our debt-to- cap ratio is about 30% and we have significant availability under our revolving credit facility. Accordingly, we believe we are well positioned for future growth. We believe 2010 will be an exciting year for Concho in an environment of higher oil prices and moderate service costs. During 2010, we plan to average operating over 20 drilling rigs in the Permian Basin. This will be a record level of drilling activity for the Company and represents a significant percentage of all the drilling activity in the basin. We expect that our 2010 drilling activity will result in meaningful production growth during the year.

As a final note, I continue to believe that our capital spending should be funded substantially out of cash flow; however, our capital structure and liquidity now allow us to view our cash flow over a longer time horizon. For example, while last year we made capital budget adjustments quarterly to remain within cash flow, we believe that we are now able to take a longer view, which we expect will ultimately make our drilling program more efficient.

In summary, 2009 was a good year for the Company and we expect to build on this success in 2010. Thank you once again for your continued support and confidence in Concho.

Tleach

Timothy A. Leach
Chairman of the Board, Chief Executive Officer and President

CONCHO IS ONE OF THE MOST ACTIVE DRILLERS IN THE PERMIAN BASIN

During the extreme commodity price fluctuations in 2009, Concho was able to maintain an active drilling program and in the process became the most active driller in the Permian Basin. We ended 2008 operating fourteen rigs, dropped to a low of nine operated drilling rigs and ended 2009 operating nineteen rigs.

In 2009, we drilled or participated in 361 wells (314 operated) and we increased our average net daily production from 25.2 thousand barrels of oil equivalent per day ("MBoepd") in the fourth quarter of 2008 to 30.6 MBoepd in the fourth quarter of 2009. At December 31, 2009, Concho had identified 3,695 drilling locations, with proved undeveloped reserves associated with 1,693 of such locations.

The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons and enhanced recovery potential.

NEW MEXICO PERMIAN

The New Mexico Permian asset is located along the northern shelf edge of the Delaware Basin, primarily in Lea, Eddy and Chaves Counties. At December 31, 2009, we identified 1,592 drilling locations on our New Mexico Permian assets, with proved undeveloped reserves attributable to 676 of such locations. Of these drilling locations, we identified 1,118 locations intended to evaluate the Yeso formation. Our New Mexico Permian asset represented 61% of our year end total proved reserves, or 128.6 million barrels of oil equivalent ("MMBoe") (65% oil, 52% proved developed). In 2009, we drilled or participated in 205 wells (193 operated). Beginning in the second quarter of 2009 and continuing through the end of 2009, we operated seven drilling rigs targeting the Yeso formation.

TEXAS PERMIAN

The primary objective in the Texas Permian asset is the Wolfberry in the Midland Basin. Wolfberry is the term applied to the combined Spraberry and Wolfcamp target intervals which are typically encountered at depths of 7,000 to 10,500 feet. The Wolfberry is comprised of a sequence of basinal, interbedded shales and carbonates.

In December 2009, we closed two acquisitions in the Wolfberry significantly increasing our average working interest in our overall Wolfberry inventory. These acquisitions in this growing core area increased our future drilling inventory by adding approximately 300 net locations to the Company's inventory. At year end 2009, we had identified 1,795 drilling locations in the Texas Permian, with proved undeveloped reserves associated with 966 of such locations.

Our Texas Permian assets represented 36% of our year end total proved reserves, or 77.2 MMBoe (71% oil, 44% proved developed). In 2009, we drilled or participated in 120 wells (117 operated). As of December 31, 2009, we were operating nine rigs in the play with plans to add four more rigs on the newly acquired properties by the end of the second quarter of 2010.

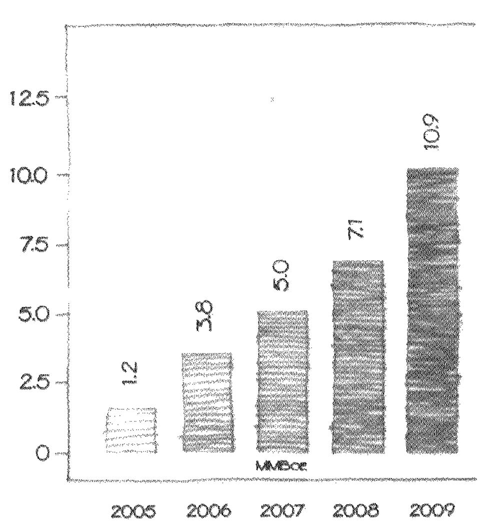
LOWER ABO

We also have made encouraging strides in the Lower Abo horizontal oil play. We participated in eight wells (four operated) during 2009 and increased our net acreage position from 21,638 at year end 2008 to 48,401 acres at year end 2009.

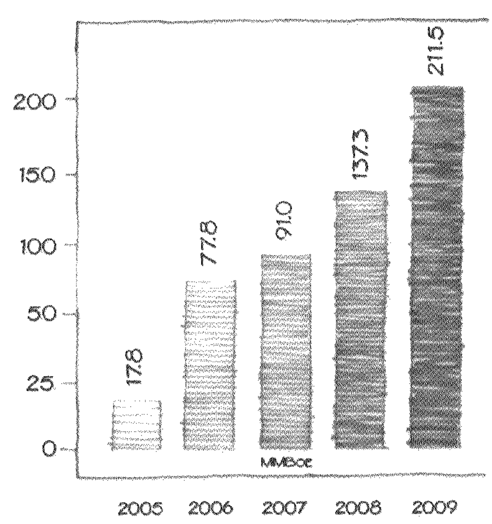
NORTH DAKOTA BAKKEN

The North Dakota Bakken continues to be an excellent complement to our core areas. We participated in 25 non-operated wells during 2009 in Mountrail and McKenzie Counties, North Dakota. In 2010, we plan to test the Three Forks formation in addition to continued activity in the Bakken.

ANNUAL PRODUCTION



PROVED RESERVES



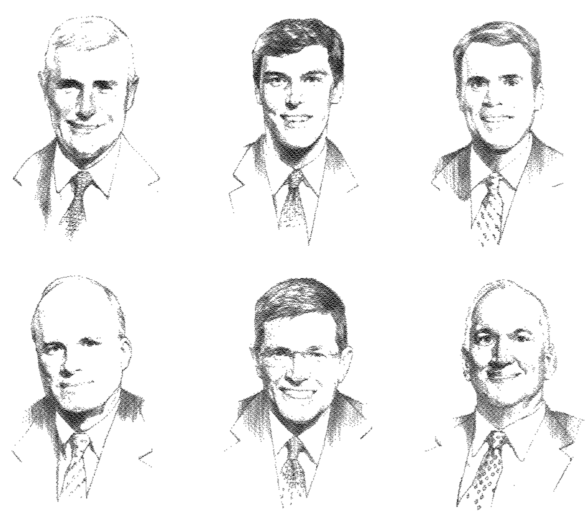
CONCHO RESOURCES

DIRECTORS AND OFFICERS

DIRECTORS OF CONCHO RESOURCES

Pictured from Left to Right:
Timothy A. Leach, Steven L. Beal, Tucker S. Bridwell, William H. Easter III, W. Howard Keenan, Jr., Ray M. Poage, Mark B. Puckett and A. Wellford Tabor.

OFFICERS OF CONCHO RESOURCES



Pictured from Left to Right:
Timothy A. Leach, C. William Giraud, Jack F. Harper, Darin G. Holderness, Matthew G. Hyde and E. Joseph Wright.

DIRECTORS

Timothy A. Leach
Steven L. Beal
Tucker S. Bridwell
William H. Easter III
W. Howard Keenan, Jr.
Ray M. Poage
Mark B. Puckett
A. Wellford Tabor

CORPORATE OFFICERS

Timothy A. Leach
Chairman of the Board, Chief Executive Officer and President

C. William Giraud
Vice President–General Counsel and Secretary

Jack F. Harper
Vice President–Business Development and Capital Markets

Darin G. Holderness
Vice President–Chief Financial Officer and Treasurer

Matthew G. Hyde
Vice President–Exploration and Land

E. Joseph Wright
Vice President–Engineering and Operations

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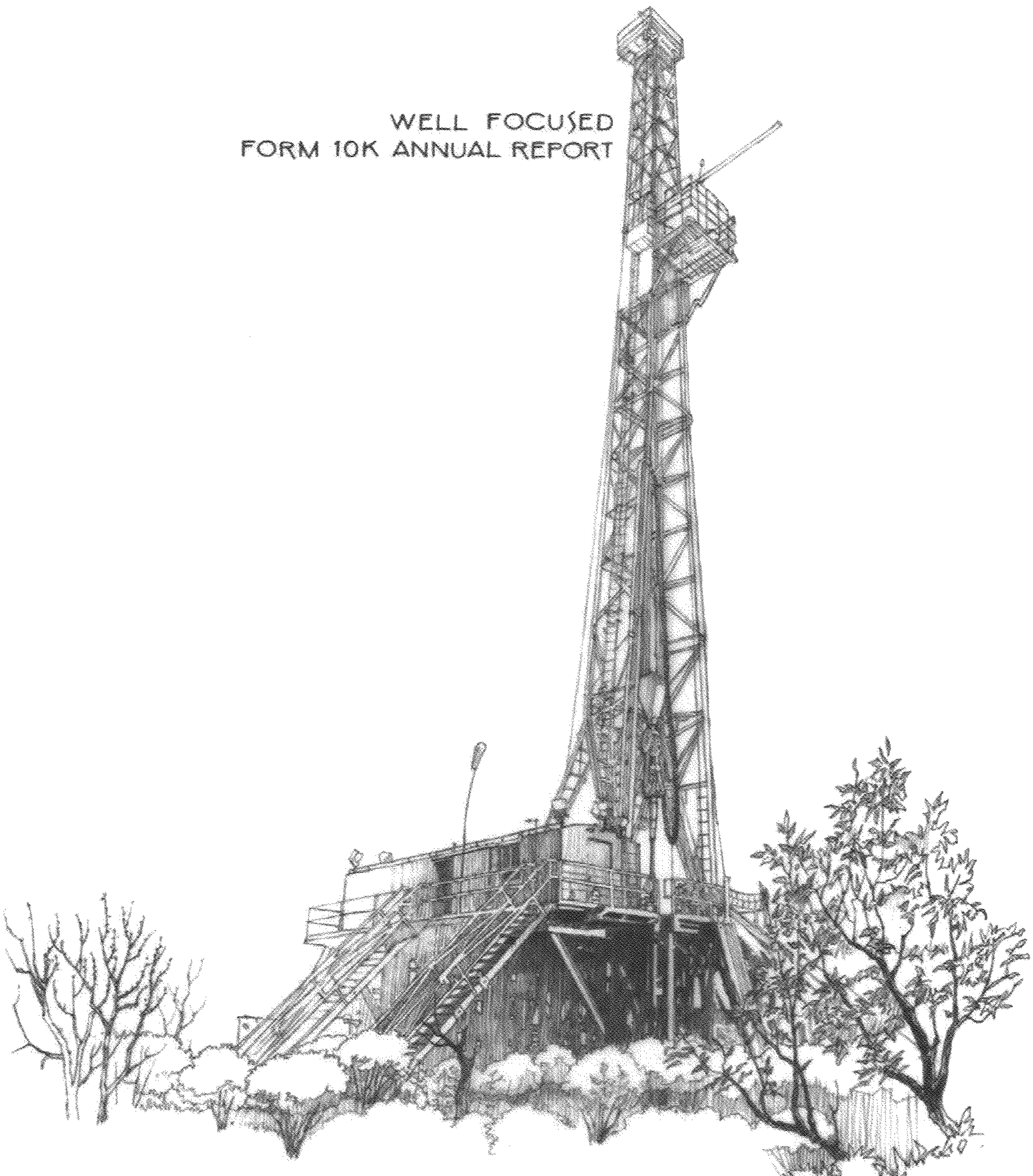
FORM 10K ANNUAL REPORT



CONCHO

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the year ended December 31, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
550 West Texas Avenue, Suite 100 Midland, Texas	**79701**
(Address of principal executive offices)	*(Zip code)*

(432) 683-7443

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $2,266,962,068

Number of shares of registrant's common stock outstanding as of February 24, 2010: 91,294,108

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2010 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2009, are incorporated by reference into Part III of this report for the year ended December 31, 2009.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). These forward-looking statements may include projections and estimates concerning capital expenditures, our liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of our business strategy and other statements concerning our operations, economic performance and financial condition. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; we disclaim any obligation to update or revise these statements unless required by securities law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in "Item 1A. Risk Factors," as well as those factors summarized below:

- sustained or further declines in the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves, including uncertainties about the effects of the SEC's new rules governing oil and natural gas reserve reporting;
- drilling and operating risks;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;
- potential financial losses or earnings reductions from our commodity price risk management program;
- shortages of oilfield equipment, services and qualified personnel and increased costs for such equipment, services and personnel;
- risks and liabilities associated with acquired properties or businesses;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically or in the jurisdictions in which we operate;
- competition in the oil and natural gas industry;
- uncertainty concerning our assumed or possible future results of operations; and
- our existing indebtedness.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I

Item 1. *Business*

General

Concho Resources Inc., a Delaware corporation ("Concho," "Company," "we," "us" and "our") is an independent oil and natural gas company engaged in the acquisition, development and exploration of oil and natural gas properties. Our core operating areas are located in the Permian Basin region of Southeast New Mexico and West Texas, a large onshore oil and natural gas basin in the United States. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons and enhanced recovery potential. We refer to our two core operating areas as the (i) New Mexico Permian, where we primarily target the Yeso formation, and (ii) Texas Permian, where we primarily target the Wolfberry, a term applied to the combined Wolfcamp and Spraberry horizons. These core operating areas are complemented by activities in our emerging plays, which include the Lower Abo horizontal play in Southeast New Mexico and the Bakken/Three Forks play in North Dakota. We intend to grow our reserves and production through development drilling and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

We were formed in February 2006 as a result of the combination of Concho Equity Holdings Corp. and a portion of the oil and natural gas properties and related assets owned by Chase Oil Corporation ("Chase Oil") and certain of its affiliates. Concho Equity Holdings Corp., which was subsequently merged into one of our wholly-owned subsidiaries, was formed in April 2004 and represented the third of three Permian Basin-focused companies that have been formed since 1997 by certain members of our current management team (the prior two companies were sold to large domestic independent oil and natural gas companies).

Wolfberry Acquisitions

In December 2009, we closed two significant acquisitions of interests in producing and non-producing assets in the Wolfberry play in the Permian Basin for approximately $260 million, subject to usual and customary post-closing adjustments (the "Wolfberry Acquisitions"). The Wolfberry Acquisitions were primarily funded with borrowings under our credit facility. As of December 31, 2009, these acquisitions included estimated total proved reserves of 19.9 MMBoe, of which 69 percent were oil and 25 percent were proved developed. Our 2009 results of operations do not include any production, revenues or costs from the Wolfberry Acquisitions.

Henry Entities Acquisition

On July 31, 2008, we closed our acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (which we refer to collectively as the "Henry Entities"), together with certain additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities (known as "along-side interests"). We paid approximately $583.7 million in net cash for the acquisition of the Henry Entities and the related acquisition of the along-side interests, which was funded with (i) borrowings under our credit facility and (ii) net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock. The oil and natural gas assets acquired in the acquisition of the Henry Entities and the along-side interests (which we refer to as the "Henry Properties") contained approximately 30.1 MMBoe of net proved reserves at the acquisition date.

Business and Properties

Our core operations are focused in the Permian Basin of Southeast New Mexico and West Texas. It underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from approximately 1,000 feet to over 25,000 feet. At December 31, 2009, 97.3 percent of our total estimated net proved reserves were located in our core operating areas and consisted of approximately 67.2 percent oil and 32.8 percent natural gas. We have assembled a multi-year inventory of development drilling and exploration projects, including projects to further evaluate the aerial extent of the Yeso formation and the Wolfberry play, that we believe will allow us to grow proved reserves and production. We also have significant acreage positions in active emerging plays in the Lower Abo horizontal play in Southeast New Mexico and the Bakken/Three Forks play in North Dakota. We view an emerging play as an area where we can acquire large undeveloped acreage positions and apply horizontal drilling and/or advanced fracture stimulation technologies to achieve economic and repeatable production results.

The following table sets forth information with respect to drilling wells commenced during the periods indicated:

	Years Ended December 31, 2009	2008
Gross wells	361.0	243.0
Net wells	230.3	157.2
Percent of gross wells:		
Producers	81.7%	86.8%
Unsuccessful	0.6%	0.4%
Awaiting completion at year-end	17.7%	12.8%
	100.0%	100.0%

We produced approximately 10.9 MMBoe and 7.1 MMBoe of oil and natural gas during 2009 and 2008, respectively. In addition, we increased our average net daily production from 25.4 MBoe during the fourth quarter of 2008 to 30.9 MBoe during the fourth quarter of 2009. During 2009, we increased our total estimated net proved reserves by approximately 74.2 MMBoe, including acquisitions.

Summary of Core Operating Areas and Emerging Plays

The following is a summary of information regarding our core operating areas and emerging plays that are further described below:

Areas	December 31, 2009: Total Proved Reserves (Mboe)	PV-10 ($ in millions)	% Oil	% Proved Developed	Gross Identified Drilling Locations	Total Gross Acreage	Total Net Acreage	Year Ended December 31, 2009 Average Net Daily Production (Boe per Day)
Core Operating Areas:								
New Mexico Permian	128,605	$1,824.3	65.2%	52.1%	1,592	150,214	69,931	19,586
Texas Permian	77,173	856.9	70.5%	44.0%	1,795	287,961	91,135	8,113
Emerging Plays:								
Lower Abo	2,707	51.3	63.3%	54.6%	152	59,179	48,401	1,581
Bakken/Three Forks	2,642	30.4	77.6%	35.2%	146	42,210	11,193	511
Other	376	1.9	3.0%	83.8%	10	140,238	56,287	155
Total	211,503(a)	$2,764.8(b)	67.1%	49.0%	3,695(c)	679,802	276,947	29,946

(a) Includes additions of 13.6 MMBoe resulting from the adoption of the new SEC rules related to disclosures of oil and natural gas reserves that are effective for fiscal years ending on or after December 31, 2009. For more information on the comparability of our reserves as a result of the new SEC rules, see "Item 1A. Risk Factors and Item 2. Properties."

(b) Our Standardized Measure at December 31, 2009 was $1,922.0 million. PV-10 is a Non-GAAP financial measure and is derived from the Standardized Measure which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See "Item 1. Business — Non-GAAP Financial Measures and Reconciliations."

(c) Of the 3,695 gross identified drilling locations, 1,726 locations were associated with proved reserves.

Core operating areas

New Mexico Permian. This area represents our most significant concentration of assets and, at December 31, 2009, we had estimated proved reserves in this area of 128.6 MMBoe, or 60.8 percent of our total net proved reserves and 66.0 percent of our PV-10.

Within this area we target two distinct producing areas, which we refer to as the shelf properties and the basinal properties. The shelf properties generally produce from the Yeso, San Andres and Grayburg formations, with producing depths ranging from approximately 900 feet to 7,500 feet. The basinal properties generally produce from the Strawn, Atoka, Morrow, Delaware and Bone Springs formations, with producing depths generally ranging from 5,000 feet to 15,000 feet.

During the year ended December 31, 2009, we commenced drilling or participated in the drilling of 205 (188.8 net) wells in this area, of which 180 (169.3 net) wells were completed as producers and 25 (19.5 net) wells were in various stages of drilling and completion at December 31, 2009. During 2009, we continued our (i) development of the Blinebry interval of the Yeso formation, the top of which is located approximately 400 feet below the top of the Paddock interval of the Yeso formation, (ii) evaluation of drilling on 10 acre spacing in the Blinebry interval and (iii) evaluation of the use of larger fracture stimulation procedures in the completion of certain wells.

At December 31, 2009, we had 150,214 gross (69,931 net) acres in this area. At December 31, 2009, on our properties in this area, we had identified 1,592 drilling locations, with proved undeveloped reserves attributed to 676 of such locations. Of these drilling locations, we identified 915 locations intended to evaluate both the Blinebry and the Paddock intervals, while 15 locations are intended to target only the Blinebry interval and 188 locations are intended to target only the Paddock interval.

Texas Permian. At December 31, 2009, our estimated proved reserves of 77.2 MMBoe in this area accounted for 36.5 percent of our total net proved reserves and 31.0 percent of our PV-10.

Our primary objective in the Texas Permian area is the Wolfberry in the Midland Basin. "Wolfberry" is the term applied to the combined production from the Spraberry and Wolfcamp horizons, which are typically encountered at depths of 7,500 to 10,500 feet. These formations are comprised of a sequence of basinal, interbedded shales and carbonates. We also operate and develop properties on the Central Basin Platform targeting the Grayburg, San Andres and Clearfork formations, which are shallower, and are typically encountered at depths of 4,500 to 7,500 feet. The reservoirs in these formations are largely carbonates, limestones and dolomites.

At December 31, 2009, we had 287,961 gross (91,135 net) acres in this area. In addition, at December 31, 2009, we had identified 1,795 drilling locations, with proved undeveloped reserves attributed to 966 of such locations.

During 2009, we commenced drilling or participated in the drilling of 120 (34.9 net) wells in this area, of which 84 (23.3 net) wells were completed as producers, 2 (0.4 net) wells were unsuccessful and 34 (11.2 net) wells were in various stages of drilling and completion at December 31, 2009.

Emerging plays

We are actively involved in drilling or participating in drilling activities in two emerging plays, in which we had 5.3 MMBoe of proved reserves at December 31, 2009.

Lower Abo horizontal play. The Lower Abo horizontal play is an oil play along the northwestern rim of the Delaware Basin in Lea, Eddy and Chaves Counties, New Mexico. This play is found at vertical depths ranging from 6,500 feet to 10,000 feet and is being developed utilizing horizontal drilling techniques and advanced fracture and stimulation technology.

At December 31, 2009, we held interests in 59,179 gross (48,401 net) acres in this play. During 2009, we commenced participation in the drilling of 8 (2.9 net) wells in this play, of which 6 (1.9 net) wells were completed as producers and 2 (1.0 net) wells were in various stages of drilling and completion at December 31, 2009. At December 31, 2009, we had 2.7 MMBoe of proved reserves in this play.

Bakken/Three Forks play. Our acreage in the Bakken/Three Forks play is in the Williston Basin in North Dakota, primarily in Mountrail and McKenzie Counties. These Mississippian/Devonian age horizons consist of siltstones encased within and below a highly organic oil-rich shale package. These horizons are found at vertical depths ranging from 9,000 feet to 11,000 feet and are being developed utilizing horizontal drilling techniques and advanced fracture and stimulation technology.

At December 31, 2009, we held interests in 42,210 gross (11,193 net) acres in this play. During 2009, we commenced participation in the drilling of 25 (3.7 net) wells in this play which 18 (2.8 net) wells were producing and 7 (0.8 net) wells were in various stages of drilling and completion at December 31, 2009. At December 31, 2009, we had 2.6 MMBoe of proved reserves in this play.

Drilling Activities

The following table sets forth information with respect to wells drilled and completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	211.0	139.2	118.0	76.8	60.0	38.5
Dry	—	—	—	—	—	—
Exploratory wells						
Productive	125.0	83.3	93.0	63.2	55.0	48.0
Dry	3.0	0.6	1.0	1.0	2.0	1.2
Total wells						
Productive	336.0	222.5	211.0	140.0	115.0	86.5
Dry	3.0	0.6	1.0	1.0	2.0	1.2
Total	339.0	223.1	212.0	141.0	117.0	87.7

The following table sets forth information about our wells for which drilling was in progress or are pending completion at December 31, 2009, which are not included in the above table:

	Drilling In-progress		Pending Completion	
	Gross	Net	Gross	Net
Development wells	11.0	5.3	35.0	19.8
Exploratory wells	7.0	2.5	11.0	2.9
Total	18.0	7.8	46.0	22.7

Our Production, Prices and Expenses

The following table sets forth summary information concerning our production results, average sales prices and operating costs and expenses for the years ended December 31, 2009, 2008 and 2007. See additional information on individual fields that are 15 percent or more of proved reserves at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations." The actual historical data in this table excludes results from the (i) Wolfberry Acquisitions and (ii) Henry Properties for periods prior to August 1, 2008.

	Years Ended December 31,		
	2009	2008	2007
Production and operating data:			
Net production volumes:			
Oil (MBbl)	7,336	4,586	3,014
Natural gas (MMcf)	21,568	14,968	12,064
Total (MBoe)	10,931	7,081	5,025
Average daily production volumes:			
Oil (Bbl)	20,099	12,530	8,258
Natural gas (Mcf)	59,090	40,896	33,052
Total (Boe)	29,947	19,346	13,766
Average prices:			
Oil, without derivatives (Bbl)	$ 57.98	$ 91.92	$ 68.58
Oil, with derivatives (Bbl)(a)	$ 68.18	$ 83.55	$ 64.90
Natural gas, without derivatives (Mcf)	$ 5.52	$ 9.59	$ 8.08
Natural gas, with derivatives (Mcf)(a)	$ 6.03	$ 9.64	$ 8.33
Total, without derivatives (Boe)	$ 49.81	$ 79.80	$ 60.52
Total, with derivatives (Boe)(a)	$ 57.65	$ 74.49	$ 58.93
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 5.82	$ 6.31	$ 5.56
Oil and natural gas taxes	$ 4.07	$ 6.57	$ 5.24
General and administrative	$ 4.78	$ 5.76	$ 5.01
Depreciation, depletion and amortization	$ 18.86	$ 17.50	$ 15.28

(a) Includes the effect of (i) commodity derivatives designated as hedges and reported in oil and natural gas sales and (ii) includes the cash payments/receipts from commodity derivatives not designated as hedges and reported in operating costs and expenses. The following table reflects the amounts of cash payments/receipts from commodity derivatives not designated as hedges that were included in computing average prices with derivatives and reconciles to the amount in gain (loss) on derivatives not designated as hedges as reported in the statements of operations:

	Years Ended December 31, 2009	2008	2007
		(In thousands)	
Oil and natural gas sales:			
Cash payments on oil derivatives	$ —	$ (30,591)	$(11,091)
Cash receipts from natural gas derivatives	—	—	188
Designated natural gas cash flow hedges reclassified from accumulated other comprehensive income	—	(696)	1,103
Total effect on oil and natural gas sales	$ —	$ (31,287)	$ (9,800)
Gain (loss) on derivatives not designated as hedges:			
Cash (payments on) receipts from oil derivatives	$ 74,796	$ (7,780)	$ —
Cash receipts from natural gas derivatives	10,955	1,426	1,815
Cash payments on interest rate derivatives	(3,335)	—	—
Unrealized mark-to-market gain (loss) on commodity and interest rate derivatives	(239,273)	256,224	(22,089)
Gain (loss) on derivatives not designated as hedges	$(156,857)	$249,870	$(20,274)

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash payments/receipts from commodity derivatives that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2009:

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Core Operating Areas:						
New Mexico Permian	1,744	191	1,935	1,171.6	55.4	1,227.0
Texas Permian	1,740	69	1,809	463.7	10.8	474.5
Emerging Plays:						
Lower Abo	20	—	20	9.2	—	9.2
Bakken/Three Forks	40	—	40	5.2	—	5.2
Other	25	131	156	1.2	5.9	7.1
Total	3,569	391	3,960	1,650.9	72.1	1,723.0

Marketing Arrangements

General. We market our crude oil and natural gas in accordance with standard energy practices utilizing certain of our employees and external consultants, in each case in consultation with our products group, asset managers and our corporate reservoir engineers. The marketing effort is coordinated with our operations group as it relates to the planning and preparation of future drilling programs so that available markets can be assessed and secured. This planning also involves the coordination of procuring the physical facilities necessary to connect new producing wells as efficiently as possible upon their completion.

Oil. We do not refine or process the crude oil we produce. A significant portion of our crude oil is connected directly to pipelines via gathering facilities in the respective field locations throughout Southeast New Mexico, while a significant portion of our production in West Texas is transported by truck. The oil is then delivered either to hub facilities located in Midland, Texas or Cushing, Oklahoma or to third party refineries located in Southeast New Mexico and the Panhandle and Gulf Coast area of Texas, with the majority of our crude oil going to a refinery in Southeast New Mexico. This oil is also transported to the hub facilities and refineries mentioned above. We sell the majority of the oil we produce under contracts using market-based pricing. This price is then adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering and delivery infrastructure in the areas of our production and evaluate market options to obtain the best price reasonably available under the circumstances. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to term agreements that extend at least three years from the date of the subject contract.

The majority of the natural gas we sell is casinghead gas sold at the lease under a percentage of proceeds processing contract. The purchaser gathers our casinghead natural gas in the field where produced and transports it via pipeline to a natural gas processing plant where the liquid products are extracted. The remaining natural gas product is residue gas, or dry gas, which is gathered at the wellhead and delivered into the purchaser's residue or mainline transportation system. Under our percentage of proceeds contract, we receive a percentage of the value for the extracted liquids and the residue gas. Each of the liquid products has its own individual market and is therefore priced separately.

In many cases, the natural gas gathering and transportation is performed by a third party gathering company which transports the production from the production location to the purchaser's mainline. The majority of our dry gas and residue gas is subject to term agreements that extend at least three years from the date of the subject contract.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2009, revenues from oil and natural gas sales to Navajo Refining Company, L.P. and DCP Midstream, LP accounted for approximately 38 percent and approximately 13 percent, respectively, of our total operating revenues. While the loss of either of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of either of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the regions in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties, contracting for drilling and workover equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to the competition for drilling and workover equipment we are also affected by the availability of related equipment. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay developmental drilling, workover and exploration activities and cause significant price increases. The past shortages of personnel made it difficult to attract and retain personnel with experience in the oil and natural gas industry and caused us to increase our general and administrative budget. We are unable to predict the timing or duration of any such shortages.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights. Although we regularly evaluate acquisition opportunities and submit bids as part of our growth strategy, we do not have any current agreements, understandings or arrangements with respect to any material acquisition.

Applicable Laws and Regulations

Regulation of the Oil and Natural Gas Industry

Regulation of transportation of oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the "FERC") regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system that permits a pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC approved index. On March 21, 2006, FERC issued a decision setting the index for the period July 1, 2006 through July 2011 at the Producer Price Index for Finished Goods (the "PPI-FG") plus 1.3 percent. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis at posted tariff rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of transportation and sale of natural gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "Natural Gas Act"), the Natural Gas Policy Act of 1978 (the "Natural Gas Policy Act") and regulations issued under those acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future, and market participants are prohibited from engaging in market manipulation. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although these orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

In August, 2005, Congress enacted the Energy Policy Act of 2005 (the "EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act or Natural Gas Policy Act up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. EPAct 2005 therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued a rule ("Order 704") requiring that any market participant, including a producer such as Concho, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected by these rules any differently than other producers of natural gas.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (the "Competition Bill") and H.B. 1920 (the "LUG Bill"). The Competition Bill gives the Railroad Commission of Texas the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the Railroad Commission specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the Railroad Commission with procedures unique to lost and unaccounted for natural gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the Railroad Commission with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007, and the Railroad Commission rules implementing the Railroad Commission's authority pursuant to the bills became effective on April 28, 2008. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production. The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production, and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (the "CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air emissions. The federal Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of GHGs. President Obama has expressed support for legislation to restrict or regulate emissions of GHGs. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations. This requirement could increase our operational and compliance costs and result in reduced demand for our products.

Also, on December 15, 2009, the U.S. Environmental Protection Agency (the "EPA") officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. Although our facilities were not subject to the EPA's greenhouse gas reporting rule adopted in September 2009, the EPA has indicated that it is evaluating whether the rule should be applied to oil and natural gas production activities, perhaps on a field-wide basis. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of, GHGs from our equipment and operations could require us to incur increased costs or could adversely affect demand for the oil and natural gas we produce.

Hydraulic fracturing. The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act (the "SDWA"), to subject hydraulic fracturing operations to regulation under the SDWA and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for us to perform hydraulic fracturing, which is an important component of well development. Any impairment of our ability to perform hydraulic fracturing would have a material adverse effect on our ability to produce oil and natural gas from new wells.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our well drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (the "NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

OSHA and other laws and regulation. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities during 2009. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2010. However, we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operation.

Our Employees

At December 31, 2009, we employed 284 persons. Of these, 253 worked at our Midland, Texas headquarters, including Texas field operations and 31 in our New Mexico field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at http://www.sec.gov.

We also make available free of charge through our website (www.conchoresources.com) our annual report, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measures and Reconciliations

PV-10

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In millions)	
PV-10	$2,764.8	$1,663.2	$2,138.5
Present value of future income taxes discounted at 10%	(842.8)	(464.2)	(706.7)
Standardized measure of discounted future net cash flows	$1,922.0	$1,199.0	$1,431.8

EBITDAX

We define EBITDAX as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) ineffective portion of cash flow hedges and unrealized (gain) loss on derivatives not designated as hedges, (7) interest expense, (8) bad debt expense and (9) federal and state income taxes. EBITDAX is not a measure of net income or cash flow as determined by GAAP.

Our EBITDAX measure provides additional information which may be used to better understand our operations, and it is also a material component of one of the financial covenants under our credit facility. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income, as an indicator of our operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX as used by us may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements, including by lenders pursuant to a covenant in our credit facility. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis. Further, under our credit facility, an event of default could arise if we were not able to satisfy and remain in compliance with specified financial ratios, including the maintenance of a quarterly ratio of total debt to consolidated EBITDAX of no greater than 4.0 to 1.0. Non-compliance with this ratio could trigger an event of default under our credit facility.

The following table provides a reconciliation of net income (loss) to EBITDAX:

	Concho Resources Inc.					Chase Group Properties Year Ended December 31,(a)
	Years Ended December 31,					
	2009	2008	2007	2006	2005	2005
	(In thousands)					
Net income (loss)	$ (9,802)	$ 278,702	$ 25,360	$ 19,668	$ 1,954	$74,351
Exploration and abandonments	10,660	38,468	29,098	5,612	2,666	—
Depreciation, depletion and amortization	206,143	123,912	76,779	60,722	11,485	18,646
Accretion of discount on asset retirement obligations	1,058	889	444	287	89	446
Impairments of long-lived assets	12,197	18,417	7,267	9,891	2,295	194
Non-cash stock-based compensation	9,040	5,223	3,841	9,144	3,252	—
Bad debt expense	(1,035)	2,905	—	—	—	—
Ineffective portion of cash flow hedges	—	(1,336)	821	(1,193)	1,148	—
Unrealized (gain) loss on derivatives not designated as hedges	239,273	(256,224)	22,089	—	1,966	1,062
Interest expense	28,292	29,039	36,042	30,567	3,096	—
Income tax expense (benefit)	(20,732)	162,085	16,019	14,379	2,039	—
EBITDAX	$475,094	$ 402,080	$217,760	$149,077	$29,990	$94,699

(a) The acquisition of the Chase Group Properties was substantially consummated on February 27, 2006, as a result of the combination of assets owned by Chase Oil and certain of its affiliates and Concho Equity Holdings Corp., see "Item 1. Business — General."

Item 1A. *Risk Factors*

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC, before investing in our shares. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil and natural gas prices are volatile. A decline in oil and natural gas prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of our cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of factors beyond our control, including:

- the level of consumer demand for crude oil and natural gas;
- the domestic and foreign supply of crude oil and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign crude oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain crude oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption;
- variations between product prices at sales points and applicable index prices; and
- worldwide economic conditions.

Furthermore, crude oil and natural gas prices were particularly volatile in 2009. For example, the NYMEX oil prices in 2009 ranged from a high of $81.37 to a low of $33.98 per Bbl and the NYMEX natural gas prices in 2009 ranged from a high of $6.07 to a low of $2.51 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached lows of $71.19 per Bbl and $4.78 per MMBtu, respectively, during the period from January 1, 2010 to February 24, 2010.

Declines in oil and natural gas prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our common stock.

Our estimates of proved reserves have been prepared under new SEC rules which went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This report presents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2009 was based on an unweighted average twelve month West Texas Intermediate posted price of $57.65 per Bbl for oil and a Henry Hub spot natural gas price of $3.87 per MMBtu for natural gas. As a result of this change in pricing methodology, direct comparisons of our previously-reported reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in West Texas and Southeast New Mexico. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year timeframe.

The SEC has not reviewed our or any reporting company's reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves and related PV-10 and Standardized Measure at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Drilling for and producing crude oil and natural gas are high-risk activities with many uncertainties that could cause our expenses to increase or our cash flows and production volumes to decrease.

Our future financial condition and results of operations will depend on the success of our exploration, development and production activities. Our crude oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable crude oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in crude oil and natural gas prices;
- surface access restrictions;
- loss of title or other title related issues;

- crude oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for crude oil and natural gas.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and/or natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality, quantity and interpretation of available relevant data;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of crude oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure or PV-10 included or incorporated by reference in this report should not be construed as accurate estimates of the current market value of our proved reserves. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our common stock.

If average oil prices were $1.00 per Bbl lower than the average price we used, our PV-10 at December 31, 2009, would have decreased from $2,764.8 million to $2,701.5 million. If average natural gas prices were $0.10 per Mcf lower than the average price we used, our PV-10 at December 31, 2009, would have decreased from $2,764.8 million to $2,742.0 million. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our common stock.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our crude oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of crude oil and natural gas reserves. At December 31, 2009, total debt outstanding under our credit facility was $550.0 million, and $405.9 million was available to be borrowed. Assuming the proceeds of $219.2 million from our February 2010 equity offering had been received on December 31, 2009 and were applied to reduce borrowings under our credit facility, our availability under our credit facility would have been $625 million. Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $680 million in acquisition, exploration and development activities during the year ended December 31, 2009 on our properties ($280.5 million related to acquisitions), and under our 2010 capital budget, we intend to invest approximately $625 million for exploration and development activities and acquisition of leasehold acreage, dependent on our cash flow and our commodity price outlook.

We intend to finance our future capital expenditures, other than significant acquisitions, primarily through cash flow from operations and through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the facility, which consent may be withheld by the lenders under our credit facility in their discretion. If we incur certain additional indebtedness, our borrowing base under our credit facility will be reduced. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of crude oil and natural gas we are able to produce from existing wells;
- the prices at which our crude oil and natural gas are sold;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing to satisfy our capital requirements. If cash generated from operations or cash available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our production, revenues and results of operations.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

We may not be able to obtain funding at all, or obtain funding on acceptable terms, to meet our future capital needs because of uncertainty in the credit and capital markets.

Global financial markets and economic conditions have been, and will likely continue to be, uncertain and volatile. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the ongoing weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased while the ability to obtain funds from those markets may, depending on the timing, prove difficult. Also, as a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers

In addition, our ability to obtain capital under our credit facility may be impaired because of the downturn in the financial market, including the issues surrounding the solvency of certain institutional lenders and the failure of several banks. Specifically, we may be unable to obtain adequate funding under our credit facility because:

- our lending counterparties may be unwilling or unable to meet their funding obligations;
- the borrowing base under our credit facility is redetermined at least twice a year and may decrease due to a decrease in crude oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for other reasons; or
- if any lender is unable or unwilling to fund their respective portion of any advance under our credit facility, then the other lenders thereunder are not required to provide additional funding to make up the portion of the advance that the defaulting lender refused to fund.

Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2009, we had approximately $550.0 million of outstanding debt under our credit facility, and our borrowing base was $955.9 million. The borrowing base limitation under our credit facility is semi-annually redetermined based upon a number of factors, including commodity prices and reserve levels. In addition to such semi-annual redeterminations, between redeterminations we and, if requested by 66⅔ percent of our lenders, our lenders, may each request one special redetermination. Upon a redetermination, our borrowing base could be substantially reduced, and in the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. If we incur certain additional indebtedness, our borrowing base under our credit facility will be reduced. We expect to utilize cash flow from operations, bank borrowings, equity financings and asset sales to fund our acquisition, exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

We now have, and will continue to have, a significant amount of indebtedness, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. At December 31, 2009, we had total consolidated indebtedness of approximately $845.8 million comprised of amounts outstanding under our credit facility and our 8.625% senior notes due 2017. Assuming our debt outstanding under our credit facility of $550.0 million at December 31, 2009 was held constant, if interest rates had been higher or lower by 1 percent per annum, our annual interest expense would have increased or decreased by approximately $5.5 million. At December 31, 2009, our total borrowing capacity under our credit facility was $955.9 million, of which $405.9 million was available. Assuming the proceeds of $219.2 million from our February 2010 equity offering had been received on December 31, 2009 and were applied to reduce borrowings under our credit facility, our availability under our credit facility would have been $625 million.

Our current and future indebtedness could have important consequences to you. For example, it could:

- impair our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;

- limit our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;
- limit our ability to borrow funds that may be necessary to operate or expand our business;
- put us at a competitive disadvantage to competitors that have less debt;
- increase our vulnerability to interest rate increases; and
- hinder our ability to adjust to rapidly changing economic and industry conditions.

Our ability to meet our debt service and other obligations may depend in significant part on the extent to which we can successfully implement our business strategy. We may not be able to implement or realize the benefits of our business strategy. In addition, if we fail to comply with the covenants or other terms of any agreements governing our debt, our lenders may have the right to accelerate the maturity of that debt and foreclose upon any collateral securing that debt.

Our producing properties are located primarily in the Permian Basin of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties in our core operating areas are geographically concentrated in the Permian Basin of Southeast New Mexico and West Texas. At December 31, 2009, approximately 99 percent of our proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, or interruption of the processing or transportation of oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2009, approximately (i) 49.6 percent of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and natural gas properties located in Southeast New Mexico; and (ii) 29.4 percent of our proved reserves were attributable to the Wolfberry play in West Texas. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

We periodically evaluate our unproved oil and natural gas properties for impairment, and could be required to recognize noncash charges to earnings of future periods.

At December 31, 2009, we carried unproved property costs of $218.6 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price circumstances, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize noncash charges to earnings of future periods.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties.

Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. At December 31, 2009, the net unrealized loss on our commodity price risk management contracts was approximately \$64.3 million. An average increase in the commodity price of \$10.00 per barrel of oil and \$1.00 per MMBtu for natural gas from the commodity prices at December 31, 2009, would have increased the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet at December 31, 2009, by \$85.0 million. We may continue to incur significant unrealized gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

We have entered into interest rate derivative instruments that may subject us to loss of income.

We have entered into derivative instruments designed to limit the interest rate risk under our current credit facility or any credit facilities we may enter into in the future. These derivative instruments can involve the exchange of a portion of our floating rate interest obligations for fixed rate interest obligations or a cap on our exposure to floating interest rates to reduce our exposure to the volatility of interest rates. While we may enter into instruments limiting our exposure to higher market interest rates, we cannot assure you that any interest rate derivative instruments we implement will be effective; and furthermore, even if effective these instruments may not offer complete protection from the risk of higher interest rates.

All interest rate derivative instruments involve certain additional risks, such as:

- the counterparty may default on its contractual obligations to us;
- there may be issues with regard to the legal enforceability of such instruments;
- the early repayment of one of our interest rate derivative instruments could lead to prepayment penalties; or
- unanticipated and significant changes in interest rates may cause a significant loss of basis in the instrument and a change in current period expense.

If we enter into derivative instruments that require us to post cash collateral, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness. Future collateral requirements will depend on arrangements with our counterparties and highly volatile oil and natural gas prices and interest rates.

Nonperformance by a counterparty to our derivative instruments or commodity purchase agreements could adversely affect our financial condition and results of operations.

We routinely enter into derivative instruments with a number of counterparties to reduce our exposure to changes in oil and natural gas prices and interest rates. A number of financial institutions similar to those that serve as counterparties to our derivative instruments have been adversely affected by the global credit crisis. If a counterparty to one of these derivative instruments cannot or will not perform under the contract, we will not realize the benefit of the derivative, which could adversely affect our financial condition and results of operations.

Additionally, substantially all of our accounts receivable result from oil and natural gas sales to third parties in the energy industry. Recent market conditions have resulted in downgrades to credit ratings of energy industry merchants and financial institutions, affecting the liquidity of several of our purchasers and counterparties. We extend credit to our purchasers based on each party's creditworthiness, but we generally have not required our purchasers to provide collateral support for their obligations to us and therefore have no assurances that our counterparties will have the ability to pay us. If a purchaser of our oil and natural gas production fails to meet its obligations under our commodity purchase agreement, our financial condition and results of operations could be adversely affected.

Our identified inventory of drilling locations and recompletion opportunities are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified and scheduled the drilling of certain of our drilling locations as an estimation of our future multi-year development activities on our existing acreage. At December 31, 2009, we had identified 3,695 gross drilling locations with proved undeveloped reserves attributable to 1,726 of such locations. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including (i) our ability to timely drill wells on lands subject to complex development terms and circumstances; (ii) the availability of capital, equipment, services and personnel; (iii) seasonal conditions; (iv) regulatory and third party approvals; (v) oil and natural gas prices; and (vi) drilling and recompletion costs and results. Because of these uncertainties, we may never drill the numerous potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, revenues and results of operations.

Approximately 51 percent of our total estimated net proved reserves at December 31, 2009, were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2009, approximately 51 percent of our total estimated net proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2009 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $1.2 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC's recently updated reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to write off any proved undeveloped reserves that are not developed within this five year timeframe. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

Unless we replace our crude oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our common stock.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our common stock and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

We may be unable to make attractive acquisitions or successfully integrate acquired companies, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility and the indenture governing our 8.625% senior notes due 2017 impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indenture governing our 8.625% senior notes due 2017 also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility or the indenture governing our 8.625% senior notes due 2017, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the facility or the indenture, which consent may be withheld by the lenders under our credit facility or such holders of senior notes in their sole discretion. Furthermore, given the current situation in the credit markets, many lenders are reluctant to provide consents in any circumstances, including to allow accretive transactions.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained the majority of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions will continue to contribute to our future growth. In connection these and potential future acquisitions, we are often only able to perform limited due diligence.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, or shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may incur substantial losses and be subject to substantial liability claims as a result of our crude oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil, natural gas liquids or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

President Obama's Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the United States House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" (the "ACESA"). The purpose of ACESA is to control and reduce emissions of GHGs in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth's atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17 percent (from 2005 levels) by 2020, and by over 80 percent by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA's overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

On November 5, 2009, the United States Senate Committee on Environment and Public Works approved the "Clean Energy Jobs and American Power Act of 2009" for controlling and reducing emissions of GHGs in the United States. This bill differs in certain areas from ACESA. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may approve any climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC's expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The CFTC is considering whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. Separately, the House of Representatives adopted financial regulatory reform legislation on December 11, 2009, that among other things would impose comprehensive regulation on the over-the-counter ("OTC") derivatives marketplace. This legislation would subject swap dealers and "major swap participants" to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants, and would provide the CFTC with authority to impose position limits in the OTC derivatives markets. A major swap participant generally would be someone other than a dealer who maintains a "substantial" net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the US banking system or financial markets. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of two companion bills, which are currently pending in the Energy and Commerce Committee and the Environmental and Public Works Committee of the House of Representatives and Senate, respectively, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, this legislation, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas wells in shale formations and increase our costs of compliance and doing business.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not control the development of certain of the properties in which we own interests, but do not operate, we may not be able to achieve any production from these properties in a timely manner.

At December 31, 2009, approximately 3.5 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on such nonoperated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable thereto, which may adversely affect our production, revenues and results of operations. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

A terrorist attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Common Stock

Our restated certificate of incorporation, bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66⅔ percent of the voting power of all outstanding voting stock;
- the prohibition of stockholder action by written consent; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indenture governing our 8.625% senior notes due 2017 restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Item 1B. *Unresolved Staff Comments*

There are no unresolved staff comments.

Item 2. *Properties*

Our Oil and Natural Gas Reserves

The estimates of our proved reserves, all of which were located in the United States, were based on evaluations prepared by our internal engineers and by the independent petroleum engineering firms of Cawley, Gillespie &

Associates, Inc. ("CGA") and Netherland, Sewell & Associates, Inc. ("NSAI") (or collectively "external engineers"). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB"). Of the proved reserves presented in this report at December 31, 2009, the external engineers prepared 93 percent of the estimate of proved reserves constituting 95 percent of the related total PV-10.

New SEC Reserve Rules. In December 2008, the SEC released the final rules for "Modernization of Oil and Gas Reporting" that have become effective for reserve reporting as of December 31, 2009. The modernization disclosure requirements require reporting of oil and natural gas reserves using a price based on a 12-month unweighted average of the first-day-of-the-month prices rather than year-end prices and the use of new technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserve volumes. Companies may also elect to disclose probable and possible reserves meeting new SEC definitions in SEC filed documents, as well as additional reserve cases showing pricing and cost sensitivities. In addition, companies are required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The modernization disclosure requirements went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult.

Internal controls. Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operating teams. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers and geoscience professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by our senior management and audit committee.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

Qualifications of responsible technical persons.

E. Joseph Wright has been our Vice President — Engineering and Operations and has been responsible for the corporate reservoir engineering group, since our formation in February 2006. Mr. Wright was the Vice President — Operations & Engineering of Concho Equity Holdings Corp. from its formation in April 2004 until it became a subsidiary of us. Mr. Wright was Vice President — Operations/Engineering of Concho Oil & Gas Corp. from its formation in January 2001 until its sale in January 2004. From January 2004 to April 2004, Mr. Wright was involved in private investments. Mr. Wright served in various engineering and operations positions for Concho Resources Inc. (which was a different company than the Company), including serving as its Vice President — Operations, from 1998 until its sale in June 2001. From 1982 until February 1998, Mr. Wright was employed by Mewbourne Oil Company in several operations, engineering and capital markets positions. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

Gayle Burleson has been our Manager of Corporate Engineering, a position she has held since July 2008. Ms. Burleson was Senior Reservoir Engineer for us from January 2006 until July 2008. From 1999 until 2006, Ms. Burleson was employed by BTA Oil Producers as a Senior Engineer responsible for Reservoir and Operations engineering duties in the Permian Basin, Oklahoma and North Dakota. From 1998 until 1999, Ms. Burleson was employed as a Staff Reservoir Engineer for Mobil Oil Corporation responsible for tertiary floods in Utah. From 1996 until 1998, Ms. Burleson was employed as a Senior Reservoir Engineer for Parker & Parsley Petroleum Company (now Pioneer Natural Resources Company) overseeing development in the Permian Basin and began her career in 1988 until 1996 with Exxon Corporation in various reservoir engineering capacities responsible for primary oil and natural gas fields, waterfloods and tertiary recovery floods in the Permian Basin and North Dakota. Ms. Burleson is a graduate of Texas Tech University with a Bachelor of Science in Chemical Engineering.

CGA. Approximately 84 percent of the reserves estimates shown herein have been independently prepared by CGA, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 25, 2010, filed as part of this report, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineering at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 22 years of practical experience in petroleum engineering, with over 20 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a BS in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

NSAI. Approximately 9 percent of the reserves estimates shown herein have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 19, 2010, filed as part of this report, was Mr. G. Lance Binder. Mr. Binder has been a practicing consulting petroleum engineering at NSAI since 1983. Mr. Binder is a Registered Professional Engineer in the State of Texas (License No. 61794) and has over 30 years of practical experience in petroleum engineering, with over 29 years experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1978 with a Bachelor of Science Degree in Chemical Engineering. Mr. Binder meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our oil and natural gas reserves. The following table sets forth our estimated net proved oil and natural gas reserves, PV-10 and Standardized Measure at December 31, 2009. PV-10 and Standardized Measure include the present value of our estimated future abandonment and site restoration costs for proved properties net of the present value of estimated salvage proceeds from each of these properties. Our reserve estimates and our computation of future net cash flows are based on a 12-month unweighted average of the first-day-of-the-month pricing of $57.65 per Bbl West Texas Intermediate posted oil price and on a 12-month unweighted average of the first-day-of-the-month pricing of $3.87 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property. The following table sets forth certain proved reserve information by region at December 31, 2009:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)	PV-10(a)
				(In millions)
Core Operating Areas:				
New Mexico Permian	83,820	268,711	128,605	$1,824.3
Texas Permian	54,425	136,489	77,173	856.9
Emerging Plays:				
Lower Abo	1,713	5,966	2,707	51.3
Bakken/Three Forks	2,049	3,557	2,642	30.4
Other	11	2,188	376	1.9
Total	142,018	416,911	211,503(b)	$2,764.8
Present value of future income tax discounted at 10%				(842.8)
Standardized Measure				$1,922.0

The following table sets forth our estimated net proved reserves by category at December 31, 2009:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)	Percent of Total	PV-10(a) (In millions)
Proved developed producing	56,778	196,457	89,521	42.3%	$1,500.2
Proved developed non-producing	9,800	26,319	14,186	6.7%	228.2
Proved undeveloped	75,440	194,135	107,796(b)	51.0%	1,036.4
Total proved	142,018	416,911	211,503	100.0%	$2,764.8

(a) Our Standardized Measure at December 31, 2009 was $1,922.0 million. PV-10 is a Non-GAAP financial measure and is derived from the Standardized Measure which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See "Item 1. Business — Non-GAAP Financial Measures and Reconciliations."

(b) Includes additions of 13.6 MMBoe resulting from the adoption of the new SEC rules related to disclosures of oil and natural gas reserves that are effective for fiscal years ending on or after December 31, 2009. For more information on the comparability of our reserves as a result of the new SEC rules, see "Item 1A. Risk Factors."

Proved undeveloped reserves. The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2009 (dollars in thousands):

Year Ended December 31,(a)	Future Production (MBoe)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
2010	2,773	$ 140,379	$ 15,606	$ 335,932	$ (211,159)
2011	6,693	334,169	39,972	338,572	(44,375)
2012	9,745	481,341	61,134	343,472	76,735
2013	10,002	491,888	67,462	140,537	283,889
2014	8,519	419,546	63,749	42,382	313,415
Thereafter	70,064	3,412,344	1,075,053	—	2,337,291
Total	107,796(b)	$5,279,667	$1,322,976	$1,200,895	$2,755,796

(a) Beginning in 2011 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling from the preceding years beginning in 2010.

(b) Includes additions of 13.6 MMBoe resulting from the adoption of the new SEC rules related to disclosures of oil and natural gas reserves that are effective for fiscal years ending on or after December 31, 2009. For more information on the comparability of our reserves as a result of the new SEC rules, see "Item 1A. Risk Factors."

The following table sets forth, since 2008, proved undeveloped reserves converted to proved developed reserves during the respective year and the net investment required to convert proved undeveloped reserves to proved developed reserves during the year:

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			
Year Ended December 31,	Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves (In thousands)
2008(a)	4,378	15,681	6,992	$114,067
2009	7,453	19,860	10,763	131,773
Total	11,831	35,541	17,755	$245,840

(a) Our initial disclosures of our reserves occurred in our initial public offering in August 2007.

At December 31, 2009, we had 107.8 MMBoe of proved undeveloped reserves. As a result of our adoption on December 31, 2009 of the new SEC rules related to disclosure of oil and natural gas reserves, we added approximately 13.6 MMBoe of proved undeveloped reserves. The majority of the additional reserves are within our two core operating areas, the Yeso and Wolfberry. The addition is primarily attributable to booking down-spacing locations in the Yeso and Wolfberry where there was a high degree of confidence based on employed technologies that have demonstrated to yield results with consistency and repeatability.

Historically, our drilling programs were substantially funded from our cash flow and were weighted towards drilling unproven locations. Our expectation in the future is to continue to fund our drilling programs primarily from our cash flows. Based on our current expectations of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can fund from our cash flow and, if needed, our credit facility, the drilling of our current inventory of proved undeveloped locations in the next 5 years.

Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by region during the year ended December 31, 2009 (in MBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
Core Operating Areas:					
New Mexico Permian	(7,149)	45,166	4	(8)	(4,463)
Texas Permian	(2,962)	17,218	20,261	(63)	3,324
Emerging Plays:					
Lower Abo	(577)	1,068	—	—	90
Bakken/Three Forks	(187)	2,437	—	—	186
Other	(56)	53	—	—	(114)
Total	(10,931)	65,942	20,265	(71)	(977)

Production. Production volumes of 10.9 MMBoe includes a full year of production from our acquisition of the Henry Properties. Production does not include volumes from the Wolfberry Acquisitions closed in December 2009.

Extensions and discoveries. Extensions and discoveries are primarily the result of (i) extension drilling in the Yeso of Southeast New Mexico and the Wolfberry in West Texas and exploratory drilling in certain of our emerging plays and (ii) adding 13.6 MMBoe of additional proved undeveloped locations as a result of our adoption of the new SEC rules related to disclosure of oil and natural gas reserves. The majority of the additional reserves are within our two main core operating areas, the Yeso and Wolfberry. The addition is primarily attributable to booking downspacing locations in the Yeso and Wolfberry where there was a high degree of confidence based on employed technologies that have demonstrated to yield results with consistency and repeatability.

Purchases of minerals-in-place. Purchases of minerals-in-place are primarily attributable to the Wolfberry Acquisitions closed in December 2009.

Sales of minerals-in-place. We had no significant sales of minerals-in-place during 2009.

Revisions of previous estimates. Revisions of previous estimates are comprised of 2.4 MMBoe of positive revisions resulting from an increase in oil price, offset by a decrease in natural gas price and 3.4 MMBoe of negative revision resulting from technical and performance evaluations. The Company's proved reserves at December 31, 2009 were determined using the twelve month average equivalent prices of $57.65 per Bbl of oil for West Texas Intermediate and $3.87 per MMBtu of natural gas for Henry Hub spot (as required by the new SEC rules related to disclosure of oil and natural gas reserves), compared to using year-end NYMEX equivalent prices of $41.00 per Bbl of oil and $5.71 per MMBtu of natural gas at December 31, 2008.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by region at December 31, 2009:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:						
New Mexico Permian	107,528	53,144	42,686	16,787	150,214	69,931
Texas Permian	245,217	68,428	42,744	22,707	287,961	91,135
Emerging Plays:						
Lower Abo	7,949	6,607	51,230	41,794	59,179	48,401
Bakken/Three Forks	23,947	6,350	18,263	4,843	42,210	11,193
Other	11,469	1,763	128,769	54,524	140,238	56,287
Total	396,110	136,292	283,692	140,655	679,802	276,947

The following table sets forth the expiration amounts of our gross and net undeveloped acreage at December 31, 2009 by region. Expirations may be less if production is established and/or continuous development activities are undertaken beyond the primary term of the lease.

	2010(a)		2011		2012		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:								
New Mexico Permian	3,654	1,896	2,926	1,085	17,389	4,704	16,692	5,355
Texas Permian	9,396	2,211	4,739	1,213	640	58	—	—
Emerging Plays:								
Lower Abo	480	320	3,163	2,443	2,730	2,342	15,453	15,033
Bakken/Three Forks	—	—	—	—	—	—	—	—
Other	46,520	19,321	8,378	7,389	3,482	1,039	2,835	993
Total	60,050	23,748	19,206	12,130	24,241	8,143	34,980	21,381

(a) Due to market conditions and prioritization of capital, we have deemphasized exploration efforts in certain emerging plays having significant lease expirations over the next year, which includes the Delaware Basin, Central Basin Platform and Arkoma Basin in Arkansas. We have impaired a significant portion of the costs associated with these plays.

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. *Legal Proceedings*

We are party to the legal proceedings that are described in Note K of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." We are also party to other proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations.

Item 4. *Submission of Matters to a Vote of Shareholders*

We did not submit any matters to a vote of stockholders during the fourth quarter of 2009.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common stock trades on the NYSE under the symbol "CXO." The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on the NYSE.

	Price Per Share	
	High	**Low**
2008:		
First Quarter	$26.44	$17.33
Second Quarter	$40.97	$25.12
Third Quarter	$39.07	$22.31
Fourth Quarter	$27.79	$14.71
2009:		
First Quarter	$28.10	$17.29
Second Quarter	$33.57	$23.50
Third Quarter	$38.70	$25.17
Fourth Quarter	$47.00	$33.71

On February 24, 2010, the last sales price of our common stock as reported on the New York Stock Exchange was $45.48 per share.

As of February 24, 2010, there were 317 holders of record of our common stock.

Dividend Policy

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. Covenants contained in our credit facility and the indenture governing our 8.625% senior notes due 2017 restrict the payment of dividends on our common stock. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant.

Repurchase of Equity Securities

Neither we nor any "affiliated purchaser" repurchased any of our equity securities during the fourth quarter of the fiscal year ended December 31, 2009.

Item 6. *Selected Financial Data*

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

The following table shows our selected historical financial data for 2005 through 2009 and combined financial data of the oil and natural gas properties contributed to us by Chase Oil, Caza Energy LLC and other related working interest owners (which we refer to collectively as the "Chase Group Properties") for 2005. We have accounted for the combination transaction that occurred on February 27, 2006, as an acquisition by Concho Equity Holdings Corp. of the Chase Group Properties and a simultaneous reorganization such that Concho Equity Holdings Corp. became our wholly owned subsidiary.

Our historical results of operations for the periods presented below may not be comparable either from period to period or going forward, for the following reasons:

- On February 27, 2006, the initial closing of the Chase Oil transaction occurred, and we acquired the Chase Group Properties for approximately 35 million shares of common stock and approximately $409 million in cash;
- In August 2007, we completed our initial public offering of common stock from which we received proceeds of $173 million that we used to retire outstanding borrowings under our second lien term loan facility totaling $86.5 million, and to retire outstanding borrowings under our credit facility totaling $86.5 million;
- In July 2008, we closed our acquisition of the Henry Entities and additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. We paid approximately $583.7 million in net cash for the acquisition of the Henry Entities and the related acquisition of the along-side interests, which was funded with borrowings under our credit facility and net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock;
- In September 2009, we issued $300 million of 8.625% senior notes at a discount, resulting in a yield-to-maturity of 8.875 percent. Currently, the interest rate associated with the senior notes is higher than our credit facility, which will result in us having higher absolute interest rates in the foreseeable future; and
- In December 2009, we closed the Wolfberry Acquisitions for approximately $260 million in cash, subject to usual and customary post-closing adjustments. The Wolfberry Acquisitions were primarily funded with borrowings under our credit facility. As of December 31, 2009, these acquisitions included estimated total proved reserves of 19.9 MMBoe, of which 69 percent were oil and 25 percent were proved developed. Our 2009 results of operations do not include any production, revenues or costs from the Wolfberry Acquisitions.

The historical financial data below for the Chase Group Properties for 2005 is derived from the audited financial statements of the Chase Group Properties. The historical financial data below for Concho Resources Inc. for 2005 through 2009, are derived from our audited consolidated financial statements.

	Concho Resources Inc.					Chase Group Properties(b)
	Years Ended December 31,					Year Ended December 31,
	2009	2008(a)	2007	2006(b)	2005	2005
	(In thousands, except per share amounts)					
Statement of operations data:						
Operating revenues:						
Oil sales	$ 425,361	$ 390,945	$ 195,596	$ 131,773	$ 31,621	$ 73,132
Natural gas sales	119,086	142,844	98,737	66,517	23,315	46,546
Total operating revenues	544,447	533,789	294,333	198,290	54,936	119,678
Operating costs and expenses:						
Oil and natural gas production	108,118	91,234	54,267	37,822	14,635	23,277
Exploration and abandonments	10,660	38,468	29,098	5,612	2,666	—
Depreciation, depletion and amortization	206,143	123,912	76,779	60,722	11,485	18,646
Accretion of discount on asset retirement obligations	1,058	889	444	287	89	446
Impairments of long-lived assets	12,197	18,417	7,267	9,891	2,295	194
General and administrative	43,237	35,553	21,336	12,577	8,055	1,702
Stock-based compensation	9,040	5,223	3,841	9,144	3,252	—
Bad debt expense	(1,035)	2,905	—	—	—	—
Contract drilling fees — stacked rigs	—	—	4,269	—	—	—
Ineffective portion of cash flow hedges	—	(1,336)	821	(1,193)	1,148	—
(Gain) loss on derivatives not designated as hedges	156,857	(249,870)	20,274	—	5,001	1,062
Total operating costs and expenses	546,275	65,395	218,396	134,862	48,626	45,327
Income (loss) from operations	(1,828)	468,394	75,937	63,428	6,310	74,351
Other income (expense):						
Interest expense	(28,292)	(29,039)	(36,042)	(30,567)	(3,096)	—
Other, net	(414)	1,432	1,484	1,186	779	—
Total other expense	(28,706)	(27,607)	(34,558)	(29,381)	(2,317)	—
Income (loss) before income taxes	(30,534)	440,787	41,379	34,047	3,993	74,351
Income tax (expense) benefit	20,732	(162,085)	(16,019)	(14,379)	(2,039)	—
Net income (loss)	(9,802)	278,702	25,360	19,668	1,954	$ 74,351
Preferred stock dividends	—	—	(45)	(1,244)	(4,766)	
Effect of induced conversion of preferred stock	—	—	—	11,601	—	
Net income (loss) applicable to common shareholders	$ (9,802)	$ 278,702	$ 25,315	$ 30,025	$ (2,812)	
Basic earnings (loss) per share:						
Net income (loss) per share	$ (0.12)	$ 3.52	$ 0.39	$ 0.63	$ (0.70)	
Shares used in basic earnings (loss) per share	84,912	79,206	64,316	47,287	4,059	
Diluted earnings (loss) per share:						
Net income (loss) per share	$ (0.12)	$ 3.46	$ 0.38	$ 0.59	$ (0.70)	
Shares used in diluted earnings (loss) per share	84,912	80,587	66,309	50,729	4,059	
Other financial data:						
Net cash provided by operations	$ 359,546	$ 391,397	$ 169,769	$ 112,181	$ 25,070	$ 93,162
Net cash used in investing activities	(586,148)	(946,050)	(160,353)	(596,852)	(61,902)	(35,611)
Net cash provided by (used in) financing activities	212,084	541,981	19,886	476,611	45,358	(57,551)
Capital expenditures for oil and natural gas properties	684,741	1,185,831	190,634	1,226,180	72,758	32,352
EBITDAX(c)	475,094	402,080	217,760	149,077	29,990	94,699

(a) The acquisition of the Henry Entities occurred on July 31, 2008. See Note D of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) The acquisition of the Chase Group Properties was substantially consummated on February 27, 2006, as a result of the combination of assets owned by Chase Oil and certain of its affiliates and Concho Equity Holdings Corp., see "Item 1. Business — General."

(c) EBITDAX is defined as net income (loss), plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) ineffective portion of cash flow hedges and unrealized (gain) loss on derivatives not designated as hedges, (7) interest expense, (8) bad debt expense and (9) federal and state income taxes. See "Item 1. Business — Non-GAAP Financial Measures and Reconciliations."

	Concho Resources Inc.					Chase Group Properties(b)
	December 31,					December 31,
	2009	2008(a)	2007	2006(b)	2005	2005
	(In thousands)					
Balance sheet data:						
Cash and cash equivalents	$ 3,234	$ 17,752	$ 30,424	$ 1,122	$ 9,182	$ —
Property and equipment, net	2,856,289	2,401,404	1,394,994	1,320,655	170,583	149,042
Total assets	3,171,085	2,815,203	1,508,229	1,390,072	232,385	161,792
Long-term debt, including current maturities	845,836	630,000	327,404	495,500	72,000	—
Equity	1,335,428	1,325,154	775,398	575,156	109,670	150,814

(a) The acquisition of the Henry Entities occurred on July 31, 2008. See Note D of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) The acquisition of the Chase Group Properties was substantially consummated on February 27, 2006, as a result of the combination of assets owned by Chase Oil and certain of its affiliates and Concho Equity Holdings Corp., see "Item 1. Business — General."

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. Please see "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the acquisition, development and exploration of producing oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We have also acquired significant acreage positions in and are actively involved in drilling or participating in drilling in emerging plays located in the Permian Basin of Southeast New Mexico and the Williston Basin in North Dakota, where we are applying horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. Crude oil comprised 67 percent of our 211.5 MMBoe of estimated net proved reserves at December 31, 2009, and 67 percent of our 10.9 MMBoe of production for 2009. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 95.3 percent of our proved developed producing PV-10 and 66.4 percent of our 3,960 gross wells at December 31, 2009. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Factors that may impact future commodity prices, including the price of oil and natural gas, include:

- developments generally impacting the Middle East, including Iraq and Iran;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas;
- the overall global demand for oil; and
- overall North American natural gas supply and demand fundamentals, including:
  - the impact of the decline of the United States economy,
  - weather conditions, and
  - liquefied natural gas deliveries to the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our commodity derivative positions at December 31, 2009.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. In general, oil and natural gas prices were substantially lower during the comparable periods of 2009 measured against 2008.

The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2009, 2008 and 2007, as well as the high and low NYMEX price for the same periods:

	Years Ended December 31,		
	2009	2008	2007
Average NYMEX prices:			
Oil (Bbl)	$61.95	$ 99.75	$72.45
Natural gas (MMBtu)	$ 4.16	$ 8.89	$ 7.11
High / Low NYMEX prices:			
Oil (Bbl):			
High	$81.37	$145.29	$98.18
Low	$33.98	$ 33.87	$50.48
Natural gas (MMBtu):			
High	$ 6.07	$ 13.58	$ 8.64
Low	$ 2.51	$ 5.29	$ 5.38

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $83.18 and $71.19 per Bbl and $6.01 and $4.78 per MMBtu, respectively, during the period from January 1, 2010 to February 24, 2010. At February 24, 2010, the NYMEX oil price and NYMEX natural gas price were $80.00 per Bbl and $4.82 per MMBtu, respectively.

Recent Events

Equity issuance. On February 1, 2010, we issued 5,347,500 shares of our common stock at $42.75 per share. After deducting underwriting discounts of approximately $9.1 million and estimated transaction costs, we received net proceeds of approximately $219.2 million. The net proceeds from this offering were used to repay a portion of the borrowings under our credit facility.

Wolfberry acquisitions. In December 2009, we closed the Wolfberry Acquisitions for approximately $260 million in cash, subject to usual and customary post-closing adjustments. The Wolfberry Acquisitions were primarily funded with borrowings under our credit facility. As of December 31, 2009, these acquisitions included estimated total proved reserves of 19.9 MMBoe, of which 69 percent were oil and 25 percent were proved developed. Our 2009 results of operations do not include any production, revenues or costs from the Wolfberry Acquisitions.

Senior notes issuance. On September 18, 2009, we issued $300 million in principal amount of 8.625% senior notes due 2017 at 98.578 percent of par. The 8.625% senior notes will mature on October 1, 2017 and interest is paid in arrears semi-annually on April 1 and October 1 beginning April 1, 2010. We used the net proceeds of $288.2 million (net of related offering costs) to repay a portion of the borrowings under our credit facility. The senior notes are senior unsecured obligations of ours and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness.

Borrowing base. Pursuant to the terms of our credit facility, our borrowing base was to be reduced by $0.30 for every dollar of new indebtedness evidenced by unsecured senior notes or unsecured senior subordinated notes that we issue. As a result of this provision, the borrowing base under our credit facility would have been reduced by $90 million due to our issuance and sale of the senior notes. However, we received waivers of this provision from lenders representing approximately 95.4 percent of our borrowing base, resulting in an actual reduction of approximately $4.1 million in our borrowing base, which reduced our borrowing base to $955.9 million.

On October 23, 2009, our borrowing base of $955.9 million was reaffirmed by our lenders under our credit facility. At December 31, 2009, we had $405.9 million of availability under our credit facility. Assuming the proceeds of $219.2 million from our February 2010 equity offering had been received on December 31, 2009 and were applied to reduce borrowings under our credit facility, our availability under our credit facility would have been $625 million.

2010 capital budget. In December 2009, we announced our 2010 capital budget of approximately $625 million. We expect to be able to fund our 2010 capital budget substantially within our cash flow. However, our capital budget is largely discretionary, and if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our drilling and completion costs, we may reduce our capital spending program to remain substantially within our cash flow. The following is a summary of our 2010 capital budget:

	2010 Budget
	(In millions)
Drilling and recompletion opportunities in our core operating area	$502
Projects operated by third parties	8
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical	82
Facilities capital in our core operating areas	33
Total 2010 capital budget	$625

Henry Entities Acquisition

On July 31, 2008, we closed the acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (the "Henry Entities") and additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. The assets acquired in the Henry Entities acquisition, including the additional non-operated interests, are referred to as the "Henry Properties." We paid $583.7 million in cash for the Henry Properties acquisition, which was funded with borrowings under our credit facility and net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock.

Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2009, the fair value of our financial derivatives was a net liability of $66.8 million. All of our counterparties to these financial derivatives are party to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Pursuant to the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. During 2009, we entered into additional commodity derivative contracts to hedge a portion of our estimated future production. The following table summarizes information about these additional commodity derivative contracts for the year ended December 31, 2009. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price collar	600,000	$45.00 - $49.00(a)	3/1/09 - 5/31/09
Price swap	960,000	$59.44(a)	7/1/09 - 12/31/09
Price swap	273,000	$67.50(a)	8/1/09 - 12/31/09
Price swap	3,847,000	$65.81(a)	1/1/10 - 12/31/10
Price swap	2,601,000	$71.66(a)	1/1/11 - 12/31/11

	Aggregate Volume	Index Price	Contract Period
Natural gas (volumes in MMBtus):			
Price collar	1,500,000	$5.00 - $5.81(b)	10/1/09 - 12/31/09
Price collar	1,500,000	$5.00 - $5.81(b)	1/1/10 - 3/31/10
Price collar	3,000,000	$5.25 - $5.75(b)	4/1/10 - 9/30/10
Price collar	1,500,000	$6.00 - $6.80(b)	10/1/10 - 12/31/10
Price collar	1,500,000	$6.00 - $6.80(b)	1/1/11 - 3/31/11
Price swap	3,000,000	$4.31(b)	4/1/09 - 9/30/09
Price swap	1,050,000	$4.66(b)	7/1/09 - 12/31/09
Price swap	8,314,000	$6.12(b)	1/1/10 - 12/31/10
Price swap	300,000	$7.29(b)	1/1/11 - 3/31/11
Price swap	5,400,000	$6.96(b)	4/1/11 - 12/31/11
Basis swap	600,000	$0.79(c)	7/1/09 - 9/30/09
Basis swap	450,000	$0.89(c)	10/1/09 - 12/31/09
Basis swap	8,400,000	$0.85(c)	1/1/10 - 12/31/10
Basis swap	1,800,000	$0.87(c)	1/1/11 - 3/31/11
Basis swap	5,400,000	$0.76(c)	4/1/11 - 12/31/11

(a) The index prices for the oil price swaps and collars are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index prices for the natural gas price swaps and collars are based on the NYMEX-Henry Hub last trading day futures price.

(c) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

Post-2009 commodity derivative contracts. After December 31, 2009 and through February 24, 2010, we entered into the following oil and natural gas price commodity derivative contracts to hedge an additional portion of our estimated future production:

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price swap	670,000	$83.72(a)	1/1/10 - 12/31/10
Price swap	195,000	$76.85(a)	3/1/10 - 12/31/10
Price swap	792,000	$81.77(a)	1/1/11 - 12/31/11
Price swap	168,000	$89.00(a)	1/1/12 - 12/31/12
Natural gas (volumes in MMBtus):			
Price swap	418,000	$ 5.99(b)	2/1/10 - 12/31/10
Price swap	1,250,000	$ 5.55(b)	3/1/10 - 12/31/10
Price swap	5,076,000	$ 6.14(b)	1/1/11 - 12/31/11
Price swap	300,000	$ 6.54(b)	1/1/12 - 12/31/12

(a) The index price for the oil price swap is based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index prices for the natural gas price swaps are based on the NYMEX-Henry Hub last trading day futures price.

Results of Operations

The following table presents selected financial and operating information for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
Production and operating data:			
Net production volumes:			
Oil (MBbl)	7,336	4,586	3,014
Natural gas (MMcf)	21,568	14,968	12,064
Total (MBoe)	10,931	7,081	5,025
Average daily production volumes:			
Oil (Bbl)	20,099	12,530	8,258
Natural gas (Mcf)	59,090	40,896	33,052
Total (Boe)	29,947	19,346	13,766
Average prices:			
Oil, without derivatives (Bbl)	$ 57.98	$ 91.92	$ 68.58
Oil, with derivatives (Bbl)(a)	$ 68.18	$ 83.55	$ 64.90
Natural gas, without derivatives (Mcf)	$ 5.52	$ 9.59	$ 8.08
Natural gas, with derivatives (Mcf)(a)	$ 6.03	$ 9.64	$ 8.33
Total, without derivatives (Boe)	$ 49.81	$ 79.80	$ 60.52
Total, with derivatives (Boe)(a)	$ 57.65	$ 74.49	$ 58.93
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 5.82	$ 6.31	$ 5.56
Oil and natural gas taxes	$ 4.07	$ 6.57	$ 5.24
General and administrative	$ 4.78	$ 5.76	$ 5.01
Depreciation, depletion and amortization	$ 18.86	$ 17.50	$ 15.28

(a) Includes the effect of (i) commodity derivatives designated as hedges and reported in oil and natural gas sales and (ii) includes the cash payments/receipts from commodity derivatives not designated as hedges and reported in operating costs and expenses. See the table that reflects the amounts of cash payments/receipts from commodity derivatives not designated as hedges that were included in computing average prices with derivatives and reconciles to the amount in gain (loss) on derivatives not designated as hedges as reported in the statements of operations in "Item 1. Business — Our Production, Prices and Expenses."

The following table presents selected financial and operating information for the fields which represent greater than 15 percent of our total proved reserves for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,			
	2009		2008	2007
	West Wolfberry(a)	Grayburg Jackson	Grayburg Jackson	Grayburg Jackson
Production and operating data:				
Net production volumes:				
Oil (MBbl)	1,320	1,429	1,045	706
Natural gas (MMcf)	3,361	4,108	3,407	2,792
Total (MBoe)	1,880	2,114	1,613	1,171
Average prices:				
Oil, without derivatives (Bbl)	$58.30	$58.87	$94.35	$68.85
Natural gas, without derivatives (Mcf)	$ 6.03	$ 5.76	$10.67	$ 8.75
Total, without derivatives (Boe)	$51.72	$51.00	$83.68	$62.36
Production costs per Boe:				
Lease operating expenses including workovers	$ 4.86	$ 4.47	$ 4.55	$ 3.48
Oil and natural gas taxes	$ 3.77	$ 4.42	$ 7.20	$ 5.43

(a) This field was acquired as part of the acquisition of the Henry Properties on July 31, 2008.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Oil and natural gas revenues. Revenue from oil and natural gas operations was $544.4 million for the year ended December 31, 2009, an increase of $10.6 million (2 percent) from $533.8 million for the year ended December 31, 2008. This increase was due to increased production (i) as a result of the inclusion of a full year of production from the Henry Properties in 2009 and (ii) due to successful drilling efforts during 2008 and 2009, partially offset by substantial decreases in realized oil and natural gas prices. Specifically, the:

- average realized oil price (excluding the effects of derivative activities) was $57.98 per Bbl during the year ended December 31, 2009, a decrease of 37 percent from $91.92 per Bbl during the year ended December 31, 2008;

- total oil production was 7,336 MBbl for the year ended December 31, 2009, an increase of 2,750 MBbl (60 percent) from 4,586 MBbl for the year ended December 31, 2008;

- average realized natural gas price (excluding the effects of derivative activities) was $5.52 per Mcf during the year ended December 31, 2009, a decrease of 42 percent from $9.59 per Mcf during the year ended December 31, 2008; and

- total natural gas production was 21,568 MMcf for the year ended December 31, 2009, an increase of 6,600 MMcf (44 percent) from 14,968 MMcf for the year ended December 31, 2008.

Hedging activities. We utilize commodity derivative instruments in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our capital budget and expenditure plans and (iii) support the economics associated with acquisitions.

Currently, we do not designate our derivative instruments to qualify for hedge accounting. Accordingly, we reflect the changes in the fair value and settlements of our derivative instruments in the statements of operations as (gain) loss on derivatives not designated as hedges. All of our remaining hedges that historically qualified or were dedesignated from hedge accounting were settled in 2008. For further discussion and information see "(Gain) loss on derivative instruments not designated as hedges" below and Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

The following is a summary of the effects of commodity hedges that qualified for hedge accounting treatment for the year ended December 31, 2008:

	Oil Hedges	Natural Gas Hedges
	Year Ended December 31, 2008	Year Ended December 31, 2008
	(Dollars in thousands)	
Decrease in oil and natural gas revenues	$(30,591)	$ (696)
Hedged volumes (Bbls and MMBtus, respectively)	951,000	4,941,000

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2009 and 2008:

	Years Ended December 31,			
	2009		2008	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Lease operating expenses	$ 62,647	$5.73	$43,725	$ 6.17
Taxes:				
Ad valorem	5,493	0.50	2,738	0.39
Production	39,017	3.57	43,775	6.18
Workover costs	961	0.09	996	0.14
Total oil and natural gas production expenses	$108,118	$9.89	$91,234	$12.88

Among the cost components of production expenses, in general, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $62.6 million ($5.73 per Boe) for the year ended December 31, 2009, an increase of $18.9 million (43 percent) from $43.7 million ($6.17 per Boe) for the year ended December 31, 2008. The total increase in absolute amounts in lease operating expenses was due to (i) the inclusion of a full year of expenses from the wells acquired in the Henry Properties acquisition and (ii) our wells successfully drilled and completed in 2008 and 2009. The decrease in lease operating expenses on a per unit basis is due to (i) increased volumes from our successful drilling program in 2008 and 2009 that has allowed economies of scale in our cost structure and (ii) cost reductions in services and supplies, primarily as a result of the recently lower commodity prices, offset by the wells acquired in the Henry Properties acquisition, which have a higher per unit cost as compared to our historical per unit cost.

Ad valorem taxes have increased primarily as a result of the acquisition of the Henry Properties, which were highly concentrated in Texas, a state which has a higher ad valorem tax rate than New Mexico, where substantially all of our properties prior to the Henry Properties acquisition were located.

Production taxes per unit of production were $3.57 per Boe during the year ended December 31, 2009, a decrease of 42 percent from $6.18 per Boe during the year ended December 31, 2008. The decrease was directly related to the decrease in commodity prices offset by the increase in oil and natural gas revenues related to increased volumes. Over the same period, our Boe prices (before the effects of derivatives) decreased 38 percent.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2009 and 2008:

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Geological and geophysical	$ 3,663	$ 3,140
Exploratory dry holes	1,941	3,722
Leasehold abandonments and other	5,056	31,606
Total exploration and abandonments	$10,660	$38,468

Our geological and geophysical expense during the year ended December 31, 2009 was primarily attributable to continued seismic activity in our Lower Abo emerging play. During the year ended December 31, 2008, our geological and geophysical expense was primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007 and completed in 2008.

During the year ended December 31, 2009, we wrote-off an unsuccessful exploratory well in our Arkansas emerging play and two unsuccessful exploratory wells in Texas Permian area. Our exploratory dry hole expense during the year ended December 31, 2008 was primarily attributable to an unsuccessful operated exploratory well located in our Texas Permian area.

For the year ended December 31, 2009, we recorded approximately $5.1 million of leasehold abandonments, which relate primarily to the write-off of four prospects in our New Mexico Permian area and three prospects in our Texas Permian area. For the year ended December 31, 2008, we recorded $31.6 million of leasehold abandonments, which were primarily related to two prospects in our Texas and Arkansas emerging plays area.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2009 and 2008:

	Years Ended December 31,			
	2009		2008	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Depletion of proved oil and natural gas properties	$201,908	$18.47	$121,464	$17.15
Depreciation of other property and equipment	2,680	0.25	1,808	0.26
Amortization of intangible asset — operating rights	1,555	0.14	640	0.09
Total depletion, depreciation and amortization	$206,143	$18.86	$123,912	$17.50
Oil price used to estimate proved oil reserves at period end	$ 57.65		$ 41.00	
Natural gas price used to estimate proved natural gas reserves at period end	$ 3.87		$ 5.71	

Depletion of proved oil and natural gas properties was $201.9 million ($18.47 per Boe) for the year ended December 31, 2009, an increase of $80.4 million from $121.5 million ($17.15 per Boe) for the year ended December 31, 2008. The increase in depletion expense, on an absolute basis, was primarily due to (i) a full year effect of acquisition of the Henry Properties, (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2008 and 2009 and (iii) to a lesser extent the Wolfberry Acquisition in December 2009. The increase in the per Boe depletion expense was primarily due to (i) the Henry Properties acquisition, for which the depletion rate was higher than that of our historical assets and (ii) capitalized costs associated with the drilling of proved undeveloped locations which generally do not add any incremental proved reserves, offset by the increase in the oil prices between the years utilized to determine proved reserves.

On December 31, 2009, we adopted the new SEC rules related to disclosures of oil and natural gas reserves. As a result of these new SEC rules we recorded an addition 13.6 MMBoe of proved reserves. We utilized the additional proved reserves in our depletion computation in the fourth quarter of 2009. Our fourth quarter of 2009 depletion expense rate was $16.74 per Boe, which is lower than past quarters in part due to the these additional proved reserves. In the future, making comparisons to prior periods as it relates to our depletion rate may be difficult as a result of these new SEC rules.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Henry Properties acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with declines in commodity prices and well performance, we recognized a non-cash charge against earnings of $12.2 million during the year ended December 31, 2009, which was primarily attributable to natural gas related properties in our New Mexico Permian area. For the year ended December 31, 2008, we recognized a non-cash charge against earnings of $18.4 million, which was comprised primarily of fields in our emerging plays in Texas and North Dakota.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2009 and 2008:

	Years Ended December 31,			
	2009		2008	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
General and administrative expenses — recurring	$ 44,477	$ 4.06	$36,170	$ 5.11
Non-recurring bonus paid to Henry Entities' employees, see Note K	10,150	0.93	4,328	0.61
Non-cash stock-based compensation — stock options	4,285	0.39	3,101	0.44
Non-cash stock-based compensation — restricted stock	4,755	0.44	2,122	0.30
Less: Third-party operating fee reimbursements	(11,390)	(1.04)	(4,945)	(0.70)
Total general and administrative expenses	$ 52,277	$ 4.78	$40,776	$ 5.76

General and administrative expenses were $52.3 million ($4.78 per Boe) for the year ended December 31, 2009, an increase of $11.5 million (28 percent) from $40.8 million ($5.76 per Boe) for the year ended December 31, 2008. The increase in general and administrative expenses during the year ended December 31, 2009 over 2008 was primarily due to (i) a full year effect of the non-recurring bonus paid to former Henry Entities' employees, (ii) an increase in non-cash stock-based compensation and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

In connection with the Henry Entities acquisition, we agreed to pay certain of our employees, who were formerly Henry Entities' employees, a predetermined bonus amount, in addition to the compensation we pay these employees, over the two years following the acquisition. Since these employees will earn this bonus over the two years, we are reflecting the cost in our general and administrative costs as non-recurring, as it is not controlled by us. See Note K of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information related to this bonus.

We earn reimbursements as operator of certain oil and natural gas properties in which we own interests. As such, we earned reimbursements of $11.4 million and $4.9 million during the year ended December 31, 2009 and 2008, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is primarily related to the Henry Properties acquisition, as we own a lower working interest in these operated properties compared to our historical property base, so we receive a larger third-party reimbursement as compared to our historical property base and 2009 reflects a full year effect of owning the Henry Properties.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to buy a portion of our oil affected as a result of a New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount due from this purchaser of approximately $2.9 million as of December 31, 2008, and pursued a claim in the bankruptcy proceedings. In December 2009, we recovered approximately $1.0 million and accordingly reduced our allowance for bad debts and bad debt expense.

(Gain) loss on derivatives not designated as hedges. In 2007, we discontinued designating our derivative instruments to qualify for hedge accounting; see Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information related to our derivative instruments. Accordingly, we reflect changes in the fair value and settlements of our derivative instruments in our consolidated statements of operations.

The following table sets forth the cash settlements and the non-cash mark-to-market adjustment for the derivative contracts not designated as hedges for the years ended December 31, 2009 and 2008:

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Cash payments (receipts):		
Commodity derivatives — oil	$ (74,796)	$ 7,780
Commodity derivatives — natural gas	(10,955)	(1,426)
Financial derivatives — interest	3,335	—
Mark-to-market (gain) loss:		
Commodity derivatives — oil	229,897	(253,960)
Commodity derivatives — natural gas	7,958	(3,347)
Financial derivatives — interest	1,418	1,083
(Gain) loss on derivatives not designated as hedges	$156,857	$(249,870)

Interest expense. Interest expense was $28.3 million for the year ended December 31, 2009, a decrease of $0.7 million from $29.0 million for the year ended December 31, 2008. The weighted average interest rate for the years ended December 31, 2009 and 2008 was 3.4 percent and 5.1 percent, respectively. The weighted average debt balance during the years ended December 31, 2009 and 2008 was approximately $668.0 million and $450.7 million, respectively.

In September 2009, we issued $300 million of 8.625% senior notes at a discount, resulting in a yield-to-maturity of 8.875 percent. Currently, the interest rate associated with the senior notes is higher than the credit facility, which will result in us having higher absolute interest rates in the foreseeable future.

The increase in weighted average debt balance during the year ended December 31, 2009 was due primarily to borrowings in July 2008 for the acquisition of the Henry Properties. The increase in interest expense is due to an increase in the weighted average debt balance. The decrease in the weighted average interest rate is primarily due to an improvement in market interest rates, offset by the effect of our senior notes.

Income tax provisions. We recorded an income tax benefit of $20.7 million and income tax expense of $162.1 million for the years ended December 31, 2009 and 2008, respectively. The effective income tax rate for the year ended December 31, 2009 and 2008 was 67.9 percent and 36.8 percent, respectively.

In 2009 and 2008, we recorded a tax benefit of approximately $6.6 million and $5.7 million associated with a reduction in our estimated overall state tax rate and the related effect on our net deferred tax liability. In 2008, we acquired the Henry Properties and in 2009 we made the Wolfberry Acquisitions, the assets of which were primarily in the state of Texas. The state income tax rate is lower in Texas compared to New Mexico (the location of our other significant concentration of assets). Accordingly, this has caused a reduction of our overall estimated state income tax rate due to the addition of Texas assets. Also, in 2009, we recorded a benefit of approximately $1.6 million associated with revisions to our 2008 tax provision. Excluding the effect of these two items our effective income tax rate would have been 41.3 percent and 38.1 percent in 2009 and 2008, respectively, which would approximate a more "normalized" effective income tax rate.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Oil and natural gas revenues. Revenue from oil and natural gas operations was $533.8 million for the year ended December 31, 2008, an increase of $239.5 million (81 percent) from $294.3 million for the year ended December 31, 2007. This increase was primarily due to (i) the acquisition of the Henry Entities on July 31, 2008,

(ii) increased production due to successful drilling efforts during 2008 and (iii) substantial increases in realized oil and natural gas prices. In addition:

- average realized oil prices (excluding the effects of derivative activities) were $91.92 per Bbl during the year ended December 31, 2008, an increase of 34 percent from $68.58 per Bbl during the year ended December 31, 2007;
- total oil production was 4,586 MBbl for the year ended December 31, 2008, an increase of 1,572 MBbl (52 percent) from 3,014 MBbl for the year ended December 31, 2007;
- average realized natural gas prices (excluding the effects of derivative activities) were $9.59 per Mcf during the year ended December 31, 2008, an increase of 19 percent from $8.08 per Mcf during the year ended December 31, 2007;
- total natural gas production was 14,968 MMcf for the year ended December 31, 2008, an increase of 2,904 MMcf (24 percent) from 12,064 MMcf for the year ended December 31, 2007;

Hedging activities. We utilize commodity derivative instruments in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our capital budget and expenditure plans and (iii) support the economics associated with acquisitions.

In 2007, we prospectively discontinued designating our derivative instruments to qualify for hedge accounting. Accordingly, we began reflecting the changes in the fair value and settlements of our derivative instruments in the consolidated statements of operations as (gain) loss on derivatives not designated as hedges. All of our remaining hedges that historically qualified or were dedesignated from hedge accounting were settled in 2008. For further discussion and information see "(Gain) loss on derivative instruments not designated as hedges" below and Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

The following is a summary of the effects of commodity hedges that qualified for hedge accounting treatment for the years ended December 31, 2008 and 2007:

	Oil Hedges		Natural Gas Hedges	
	Years Ended December 31,		Years Ended December 31,	
	2008	2007	2008	2007
	(Dollars in thousands)			
Increase (decrease) in oil and natural gas revenues	$ (30,591)	$ (11,091)	$ (696)	$ 1,291
Hedged volumes (Bbls and MMBtus, respectively)	951,000	1,076,750	4,941,000	6,482,600

Oil and natural gas production costs. The following table provides the components of our oil and natural gas production costs for the years ended December 31, 2008 and 2007:

	Years Ended December 31,			
	2008		2007	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Lease operating expenses	$43,725	$ 6.17	$26,480	$ 5.27
Taxes:				
Ad valorem	2,738	0.39	2,012	0.40
Production	43,775	6.18	24,301	4.84
Workover costs	996	0.14	1,474	0.29
Total oil and natural gas production expenses	$91,234	$12.88	$54,267	$10.80

Among the cost components of production expenses, in general, we have control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $43.7 million ($6.17 per Boe) for the year ended December 31, 2008, an increase of $17.2 million (65 percent) from $26.5 million ($5.27 per Boe) for the year ended December 31, 2007. The increase in lease operating expenses was due to (i) the wells acquired in the Henry Properties acquisition, which increased the absolute and per unit amount because those wells have a higher per unit cost as compared to our historical per unit cost, (ii) our wells successfully drilled and completed in 2008 and (iii) general inflation of field service and supply costs associated with rising commodity prices.

Ad valorem taxes have increased primarily as a result of (i) the acquisition of the Henry Properties, which were highly concentrated in Texas, a state which has a higher ad valorem tax rate than New Mexico, where substantially all of our properties prior to the Henry Properties acquisition were located and (ii) an increase in commodity prices.

Production taxes per unit of production were $6.18 per Boe during the year ended December 31, 2008, an increase of 28 percent from $4.84 per Boe during the year ended December 31, 2007. The increase was directly related to the increase in oil and natural gas revenues and the related increase in commodity prices. Over the same period our Boe prices (before the effects of derivatives) increased 32 percent.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2008 and 2007:

	Years Ended December 31,	
	2008	2007
	(In thousands)	
Geological and geophysical	$ 3,140	$ 4,089
Exploratory dry holes	3,722	21,923
Leasehold abandonments and other	31,606	3,086
Total exploration and abandonments	$38,468	$29,098

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the year ended December 31, 2008 was $3.1 million, a decrease of $1.0 million from $4.1 million for the year ended December 31, 2007. This decrease was primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007 and completed in 2008.

Our exploratory dry hole expense during the year ended December 31, 2008 was primarily attributable to an unsuccessful operated exploratory well located in our Texas Permian area. Our exploratory dry hole expense during the year ended December 31, 2007 was primarily attributable to three wells drilled in our Texas emerging plays area and two wells which were drilled in our New Mexico Permian area.

For the year ended December 31, 2008, we recorded $31.6 million of leasehold abandonments, which were primarily related to two prospects in our Texas and Arkansas emerging plays area. For the year ended December 31, 2007, we recorded $3.1 million of leasehold abandonments, which were primarily related to a prospect in our Texas Permian area, a prospect in our New Mexico Permian area and leasehold expiring in our New Mexico Permian area.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2008 and 2007:

	Years Ended December 31,			
	2008		2007	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Depletion of proved oil and natural gas properties	$121,464	$17.15	$75,744	$15.07
Depreciation of other property and equipment	1,808	0.26	1,035	0.21
Amortization of intangible asset — operating rights	640	0.09	—	—
Total depletion, depreciation and amortization	$123,912	$17.50	$76,779	$15.28
Oil price used to estimate proved oil reserves at period end	$ 41.00		$ 92.50	
Natural gas price used to estimate proved natural gas reserves at period end	$ 5.71		$ 6.80	

Depletion of proved oil and natural gas properties was $121.5 million ($17.15 per Boe) for the year ended December 31, 2008, an increase of $45.8 million from $75.7 million ($15.07 per Boe) for the year ended December 31, 2007. The increase in depletion expense was primarily due to (i) the Henry Properties acquisition for which the depletion rate was higher than that of our historical assets, (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2007 and 2008 and (iii) the decrease in the oil and natural gas prices between the years which were utilized to determine the proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Henry Properties acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with declines in commodity prices and well performance, we recognized a non-cash charge against earnings of $18.4 million during the year ended December 31, 2008, which was comprised primarily of a property in our New Mexico Permian area. For the year ended December 31, 2007, we recognized a non-cash charge against earnings of $7.3 million, which was comprised primarily of properties in our Texas Permian and Texas emerging plays areas.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2008 and 2007:

	Years Ended December 31,			
	2008		2007	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
General and administrative expenses — recurring	$36,170	$ 5.11	$22,419	$ 4.47
Non-recurring bonus paid to Henry Entities' employees, see Note K	4,328	0.61	—	—
Non-cash stock-based compensation — stock options	3,101	0.44	2,463	0.49
Non-cash stock-based compensation — restricted stock	2,122	0.30	1,378	0.27
Less: Third-party operating fee reimbursements	(4,945)	(0.70)	(1,083)	(0.22)
Total general and administrative expenses	$40,776	$ 5.76	$25,177	$ 5.01

General and administrative expenses were $40.8 million ($5.76 per Boe) for the year ended December 31, 2008, an increase of $15.6 million (62 percent) from $25.2 million ($5.01 per Boe) for the year ended December 31, 2007. The increase in general and administrative expenses during the year ended December 31, 2008 over 2007 was primarily due to (i) the non-recurring bonus paid to Henry Entities' employees, (ii) an increase in non-cash stock-based compensation and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

In connection with the Henry Entities acquisition, we agreed to pay certain of our employees, who were formerly Henry Entities' employees, a predetermined bonus amount, in addition to the compensation we pay these employees, over the two years following the acquisition. Since these employees will earn this bonus over the two years, we are reflecting the cost in our general and administrative costs as non-recurring, as it is not controlled by us. See Note K of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information related to this bonus.

We earn reimbursements as operator of certain oil and natural gas properties in which we own interests. As such, we earned reimbursements of $4.9 million and $1.1 million during the year ended December 31, 2008 and 2007, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is directly related to the Henry Properties acquisition, as we own a lower working interest in these operated properties compared to our historical property base, so we have a larger third-party reimbursement as compared to our historical property base.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to sell a portion of our oil production affected by a New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount of $2.9 million due from this purchaser for June and July production during the year ended December 31, 2008.

Contract drilling fees — stacked rigs. We determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the year ended December 31, 2007 of approximately $4.3 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. These costs were minimized during the first six months of 2007 as one contractor secured work for a rig for 71 days during that period and charged us only the difference between the then-current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

Gains (losses) on derivatives not designated as hedges. During the quarter ended September 30, 2007, we determined that all of our natural gas commodity derivative contracts no longer qualified as hedges. Because we no longer considered these hedges to be highly effective, we discontinued hedge accounting for those existing hedges, prospectively, and during the period the hedges became ineffective. In addition, for our commodity and interest rate derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period.

The following table sets forth the settlements and the non-cash mark-to-market adjustment for the derivative contracts not designated as hedges for the years ended December 31, 2008 and 2007:

	Years Ended December 31,	
	2008	**2007**
	(In thousands)	
Cash payments (receipts):		
Commodity derivatives — oil	$ 7,780	$ —
Commodity derivatives — natural gas	(1,426)	(1,815)
Financial derivatives — interest	—	—
Mark-to-market (gain) loss:		
Commodity derivatives — oil	(253,960)	22,988
Commodity derivatives — natural gas	(3,347)	(899)
Financial derivatives — interest	1,083	—
(Gain) loss on derivatives not designated as hedges	$(249,870)	$20,274

Interest expense. Interest expense was $29.0 million for the year ended December 31, 2008, a decrease of $7.0 million from $36.0 million for the year ended December 31, 2007. The weighted average interest rate for the years ended December 31, 2008 and 2007 was 5.1 percent and 7.7 percent, respectively. The weighted average debt balance during the years ended December 31, 2008 and 2007 was approximately $450.7 million and $436.3 million, respectively.

The increase in weighted average debt balance during the year ended December 31, 2008 was due to the Henry Properties acquisition in July 2008, offset by (i) the partial prepayment in August 2007 of $86.6 million on the 2nd lien credit facility and the repayment in August 2007 of $86.6 million on our previous revolving credit facility and (ii) a partial prepayment in March 2008 on our previous revolving credit facility utilizing cash from operations. Also, in July 2008, we repaid and terminated our 2nd lien credit facility which resulted in the write-off of approximately $1.1 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. In March 2007, we reduced our previous revolving credit facility's borrowing base by $100.0 million, or 21 percent, resulting in the write-off of $0.8 million of deferred loan costs, and repaid a term credit facility, resulting in the write-off of $0.4 million of deferred loan costs, both of which are included in interest expense. In August 2007, we made a $86.6 million partial prepayment on our 2nd lien credit facility from proceeds of our initial public offering, which resulted in the write-off of approximately $1.0 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. The decrease in the weighted average interest rate is due to (i) improvement in market interest rates and (ii) the fact that the interest rate margins under our credit facility (and previous revolving credit facility) were lower than those under our 2nd lien credit facility.

Income tax provision. We recorded an income tax expense of $162.1 million and $16.0 million for the year ended December 31, 2008 and 2007, respectively. The effective income tax rate for the year ended December 31, 2008 and 2007 was 36.8 percent and 38.7 percent, respectively. We estimated a higher effective state income rate in 2007 than in 2008, which is primarily due to our estimate of income among the various states in which we own assets.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility, proceeds from the disposition of assets or alternative financing sources, as discussed in "Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the years ended December 31, 2009, 2008 and 2007 totaled $394.0 million, $339.6 million and $180.2 million, respectively. These expenditures were primarily funded by cash flow from operations (including effects of derivative cash receipts/payments).

In December 2009, we announced our 2010 capital budget of approximately $625 million. We expect to be able to fund our 2010 capital budget substantially within our cash flow. However, our capital budget is largely discretionary, and if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our drilling and completion costs, we may reduce our capital spending program to remain substantially within our cash flow.

Other than the purchase of leasehold acreage and other miscellaneous property interests, our 2010 capital budget is exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Although we cannot provide any assurance, we believe that our available cash and cash flows will substantially fund our 2010 capital expenditures, as adjusted from time to time; however, we may also use our credit facility or other alternative financing sources to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances we would consider increasing or reallocating our 2010 capital budget.

Acquisitions. Our expenditures for acquisitions of proved and unproved properties during the years ended December 31, 2009, 2008 and 2007 totaled $280.5 million, $838.0 million and $7.3 million, respectively. The Wolfberry Acquisitions in December 2009 were funded by borrowings under our credit facility, and the Henry Properties acquisition in July 2008 was primarily funded by a private placement of our common stock and borrowings under our credit facility.

Contractual obligations. Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, employment agreements with executive officers, contractual bonus payments, derivative liabilities and other obligations.

We had the following contractual obligations at December 31, 2009:

	Payments Due by Period				
	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
			(In thousands)		
Long-term debt(a)	$ 850,000	$ —	$ —	$550,000	$300,000
Cash interest expense on debt(b)	265,769	51,330	82,550	60,733	71,156
Operating lease obligations(c)	10,012	2,291	3,033	2,386	2,302
Drilling commitments(d)	1,781	1,781	—	—	—
Employment agreements with executive officers(e)	3,930	1,965	1,965	—	—
Henry Entities bonus obligation(f)	5,763	5,763	—	—	—
Derivative liabilities(g)	91,756	62,419	29,337	—	—
Asset retirement obligations(h)	22,754	3,262	704	620	18,168
Total contractual obligations	$1,251,765	$128,811	$117,589	$613,739	$391,626

(a) See Note J of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding future interest payment obligations on the 8.625% unsecured senior notes. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on the 8.625% unsecured senior notes is estimated assuming no principal repayment until the due date of October 1, 2017. Cash interest expense on the credit facility is estimated assuming (i) a principal balance outstanding equal to the balance at December 31, 2009 of $550 million with no principal repayment until the instrument due date of July 31, 2013 and (ii) a fixed interest rate of 2.8 percent, which was our interest rate at December 31, 2009. Also included in the "Less than 1 year" column is accrued interest at December 31, 2009, for both the Senior Notes and credit facility of approximately $10.1 million.

(c) See Note K of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(d) Consists of daywork drilling contracts related to drilling rigs contracted through June 30, 2010. See Note K of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(e) Represents amounts of cash compensation we are obligated to pay to our executive officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(f) Represents bonuses we agreed to pay certain former employees of the Henry Entities at each of the first and second anniversaries of the closing of the Henry Properties acquisition. See Note K of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(g) Derivative obligations represent commodity and interest rate derivatives that were valued at December 31, 2009. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative obligations.

(h) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion. See Note E of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities (including the derivative cash receipts/payments presented in our investing activities) and financing provided by our credit facility. We believe that funds from our cash flows should be sufficient to meet both our short-term working capital requirements and our 2010 capital expenditure plans. If our cash is not sufficient we believe we have adequate availability under our credit facility to fund our cash flow deficits.

Cash flow from operating activities. Our net cash provided by operating activities was $359.5 million, $391.4 million and $169.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. The decrease in operating cash flows during the year ended December 31, 2009 over 2008 was principally due to increases in oil and natural gas production costs and general and administrative expenses, partially offset by increased oil and natural gas revenues. The increase in operating cash flows during the year ended December 31, 2008 over 2007 was principally due to (i) increases in our oil and natural gas production as a result of our exploration and development program, (ii) five months of activity from the acquired Henry Properties and (iii) increases in average realized oil and natural gas prices.

Cash flow used in investing activities. During the years ended December 31, 2009, 2008 and 2007, we invested $669.3 million, $931.9 million and $162.6 million, respectively, for additions to, and acquisitions of, oil and natural gas properties, inclusive of dry hole costs. Cash flows used in investing activities were substantially lower during the year ended December 31, 2009 over 2008, due to (i) the Henry Properties acquisition in 2008 being larger than the Wolfberry Acquisitions in 2009 and (ii) our receipts from, in 2009, compared to our payments on, in 2008, associated with derivatives not designated as hedges, offset by increased exploration and development activities in 2009. Cash flows used in investing activities were substantially higher during the year ended December 31, 2008 over 2007, primarily due to the Henry Properties acquisition, as well as increased drilling activity in 2008.

Cash flow from financing activities. Net cash provided by financing activities was $212.1 million, $542.0 million and $19.9 million for the years ended December 31, 2009, 2008 and 2007, respectively. During the year ended December 31, 2009, we net borrowed $215.7 million of debt, which was used primarily to fund the Wolfberry Acquisitions in December 2009. During the year ended December 31, 2008, we net borrowed $302.1 million of debt and issued approximately 8.3 million shares of our common stock to fund the Henry Properties acquisition. In March 2007, we entered into a $200 million 2nd lien credit facility. The proceeds were principally used to repay the outstanding balance under our prior term loan facility and to reduce the outstanding balance under our credit facility.

On September 18, 2009, we issued $300 million in principal amount of 8.625% senior notes due 2017 at 98.578 percent of par. The 8.625% senior notes will mature on October 1, 2017 and interest is paid in arrears semi-annually on April 1 and October 1 beginning April 1, 2010. We used the net proceeds of $288.2 million (net of related estimated offering costs) to repay a portion of the borrowings under our credit facility. The senior notes are senior unsecured obligations of ours and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness.

We issued the senior notes to (i) extend the maturities of our debt to better match the long-lived nature of our assets, (ii) increase liquidity under our credit facility and (iii) reduce our dependency on bank debt.

Pursuant to the terms of our credit facility (described below), our borrowing base was to be reduced by $0.30 for every dollar of new indebtedness evidenced by unsecured senior notes or unsecured senior subordinated notes that we issue. As a result of this provision, the borrowing base under our credit facility would have been reduced by $90 million due to our issuance and sale of the senior notes. However, we received waivers of this provision from lenders representing approximately 95.4 percent of our borrowing base, resulting in an actual reduction of approximately $4.1 million in our borrowing base, which reduced our borrowing base to $955.9 million.

Our credit facility, as amended, has a maturity date of July 31, 2013. At December 31, 2009, we had letters of credit outstanding under the credit facility of approximately $25,000 and our availability to borrow additional funds was approximately $405.9 million. In October 2009, the lenders reaffirmed our $955.9 million borrowing base under the credit facility until the next scheduled borrowing base redetermination in April 2010. Between scheduled borrowing base redeterminations, we and, if requested by 66⅔ percent of the lenders, the lenders, may each request one special redetermination.

Advances on the credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.25 percent at December 31, 2009) or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). At December 31, 2009, the interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 200 to 300 basis points and 112.5 to 212.5 basis points, respectively, per annum depending on the debt balance outstanding. At December 31, 2009, we pay commitment fees on the unused portion of the available borrowing base of 50 basis points per annum.

In June 2008, we entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of our common stock in a private placement (the "Private Placement") contemporaneous with the closing of the Acquisition. On July 31, 2008, we issued 8,302,894 shares of our common stock at $30.11 per share pursuant to the Private Placement. We paid the placement agent of the Private Placement a fee of approximately $7.6 million, which resulted in net proceeds to us of $242.4 million.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

On February 1, 2010, we issued 5,347,500 shares of our common stock at $42.75 per share. After deducting underwriting discounts of approximately $9.1 million and estimated transaction costs we received net proceeds of approximately $219.2 million. The net proceeds from this offering were used to repay a portion of the borrowing under our credit facility. Assuming the proceeds from this offering were received on December 31, 2009 and were applied to reduce our borrowings under our credit facility, our availability under our credit facility would have been approximately $625 million.

Financial markets. The current state of the financial markets remains uncertain; however, we have recently seen improvements in the stock market and the credit markets appear to have stabilized. There have been financial institutions that have (i) failed and been forced into government receivership, (ii) received government bail-outs, (iii) declared bankruptcy, (iv) been forced to seek additional capital and liquidity to maintain viability or (v) merged. The United States and world economy has experienced and continues to experience volatility, which continues to impact the financial markets.

At December 31, 2009, we had $405.9 million of available borrowing capacity under our credit facility. Our credit facility is backed by a syndicate of 21 banks. Even in light of the volatility in the financial markets, we believe that the lenders under our credit facility have the ability to fund additional borrowings we may need for our business.

We pay floating rate interest under our credit facility and we are unable to predict, especially in light of the uncertainty in the financial markets, whether we will incur increased interest costs due to rising interest rates. We have used interest rate derivatives to mitigate the cost of rising interest rates, and we may enter into additional interest rate derivatives in the future. Additionally, we may issue additional fixed rate debt in the future to increase available borrowing capacity under our credit facility or to reduce our exposure to the volatility of interest rates.

In the current financial markets, there is no assurance that we could refinance our credit facility with comparable terms, particularly the five-year term of our credit facility. Because our credit facility matures in July 2013, we do not expect to seek refinancing of our credit facility until 2011.

To the extent we need additional funds beyond those available under our credit facility to operate our business or make acquisitions we would have to pursue other financing sources. These sources could include issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock or (v) other securities. We may also sell assets. However, in light of the current financial market conditions there are no assurances that we could obtain additional funding, or if available, at what cost and terms.

Liquidity. Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our credit facility. At December 31, 2009, we had $3.2 million of cash on hand.

At December 31, 2009, the borrowing base under our credit facility was $955.9 million (which was reaffirmed in October 2009), which provided us with $405.9 million of available borrowing capacity. Assuming the proceeds from our February 2010 equity offering were received on December 31, 2009 and were applied to reduce our borrowings under our credit facility, our availability under our credit facility would have been approximately $625 million. Our borrowing base is redetermined semi-annually, with the next redetermination occurring in April 2010. Between scheduled borrowing base redeterminations, we and, if requested by 66⅔ percent of the lenders, the lenders, may each request one special redetermination. In general, redeterminations are based upon a number of factors, including commodity prices and reserve levels. Upon a redetermination, our borrowing base could be substantially reduced. In light of the current commodity prices and the state of the financial markets, there is no assurance that our borrowing base will not be reduced.

Book capitalization and current ratio. Our book capitalization at December 31, 2009 was $2,181.2 million, consisting of debt of $845.8 million and stockholders' equity of $1,335.4 million. Our debt to book capitalization was 39 percent and 32 percent at December 31, 2009 and 2008, respectively. Our ratio of current assets to current liabilities was 0.64 to 1.00 at December 31, 2009 as compared to 1.03 to 1.00 at December 31, 2008, which is primarily attributable to the changes in fair value of our derivative instruments.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the year ended December 31, 2009, we received an average of $57.98 per barrel of oil and $5.52 per Mcf of natural gas before consideration of commodity derivative contracts compared to $91.92 per barrel of oil and $9.59 per Mcf of natural gas in the year ended December 31, 2008. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and continued through the first six months of 2008, commodity prices for oil and natural gas increased significantly. The higher prices led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on capital costs. We expect these costs to continue to moderate during the first quarter of 2010 as a result of the recent rapid diminution in prices for oil and natural gas from 2008 peaks.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets and valuation of stock-based compensation. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities under this method. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are also capitalized. This accounting method may yield significantly different results than the full cost method of accounting. Exploratory drilling costs are initially capitalized, but are charged to expense if and when the well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing properties are sold.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively condemn our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on an individual property or unit basis based on total estimated net proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated net proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 1 to 50 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2009 was based on an unweighted average twelve month West Texas Intermediate posted price of $57.65 per Bbl for oil and a Henry Hub spot natural gas price of $3.87 per MMBtu for natural gas. As a result of this change in pricing methodology, direct comparisons to our previously-reported reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves with the required five-year time-frame.

The SEC has not reviewed our or any reporting company's reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves and related PV-10 at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions to estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Valuation of Stock-Based Compensation

Under the modified prospective accounting approach, we are required to expense all options and other stock-based compensation that vested during the year of adoption based on the fair value of the award on the grant date. The calculation of the fair value of stock-based compensation requires the use of estimates to derive the inputs necessary for using the various valuation methods utilized by us. We utilize (i) the Black-Scholes option pricing model to measure the fair value of stock options and (ii) the stock price on the date of grant for the fair value of restricted stock awards.

Recent Accounting Pronouncements

In June 2009, the FASB issued the Accounting Standards Codification (the "Codification" or "ASC") which has become the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in accordance with GAAP. All existing accounting standard documents are superseded by the Codification and any accounting literature not included in the Codification will not be authoritative. However, rules and interpretive releases of the SEC issued under the authority of federal securities laws will continue to be the source of authoritative generally accepted accounting principles for SEC registrants. Effective September 30, 2009, there are no more references made to the superseded FASB standards in our consolidated financial statements. The Codification does not change or alter existing GAAP and, therefore, did not have an impact on our financial position, results of operations or cash flows.

Business combinations. In December 2007, the FASB issued a revision to the existing business combinations guidance. The guidance establishes principles and requirements for how an acquirer recognizes and measures the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. It also establishes disclosure requirements that enable users to evaluate the nature and financial effects of the business combination. The revised standard was effective for acquisitions occurring in an entity's fiscal year beginning after December 15, 2008. We adopted the standard effective January 1, 2009, and account for all our business combinations using this standard and disclose all required information.

Fair value. In August 2009, the FASB issued an update to the Fair Value Topic of the Codification. The FASB issued the update because some entities have expressed concern that there may be a lack of observable market information to measure the fair value of a liability. The topic is effective for the first reporting period beginning after August 28, 2009, with earlier application permitted. The guidance provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. In such circumstances, the topic specifies that a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Examples of the alternative valuation methods include using a present value technique or a market approach, which is based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. The guidance also states that when estimating the fair value of a liability, a reporting entity is not required to include a separate input or adjustments to other inputs relating to the existence of a restriction that prevents the transfer of the liability. We adopted the topic effective September 30, 2009, and the adoption did not have a significant impact on our consolidated financial statements.

Oil and natural gas. In September 2009, the FASB issued an update to the Oil and Gas Topic, which makes a technical correction related to an SEC Observer comment, regarding the accounting and disclosures for natural gas balancing arrangements. The topic amends prior guidance because the SEC staff has not taken a position on whether the entitlements method or sales method is preferable for natural gas-balancing arrangements that do not meet the definition of a derivative.

With the entitlements method, sales revenue is recognized to the extent of each well partner's proportionate share of natural gas sold regardless of which partner sold the natural gas. Under the sales method, sales revenue is recognized for all natural gas sold by a partner even if the partner's ownership is less than 100 percent of the natural gas sold.

The Oil and Gas Topic update included an instruction that public companies must account for all significant natural gas imbalances consistently using one accounting method. Both the method and any significant amount of imbalances in units and value should be disclosed in regulatory filings. We currently account for all natural gas balances under the sales method and make all required disclosures.

Reserve estimation. In January 2010, the FASB issued an update to the Oil and Gas Topic, which aligns the oil and natural gas reserve estimation and disclosure requirements with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the "Final Rule"). The Final Rule was issued on December 31, 2008. The Final Rule is intended to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves, which should help investors evaluate the relative value of oil and natural gas companies.

The Final Rule permits the use of new technologies to determine proved reserves estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Final Rule will also allow, but not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Final Rule became effective for fiscal years ending on or after December 31, 2009. We adopted the ruling effective December 31, 2009, which had the effect of adding 13.6 MMBoe of proved reserves. Our fourth quarter 2009 depletion and impairment calculations were based upon proved reserves that were determined using the new reserve rules, whereas depletion and impairment calculations in previous quarters within 2009 were based on the prior SEC methodology. See reserves information in "Item 2. Properties" and in the Unaudited Supplementary Data disclosures in "Item 8. Financial Statements and Supplementary Data."

Fair value. In January 2010, the FASB issued an update to the Fair Value Topic, which enhances the usefulness of fair value measurements. The amended guidance requires both the disaggregation of information in certain existing disclosures, as well as the inclusion of more robust disclosures about valuation techniques and inputs to recurring and nonrecurring fair value measurements.

The topic amends the disclosures about fair value measurements in the Fair Value Topic as follows:

- Entities must disclose the amounts of, and reasons for, significant transfers between Level 1 and Level 2, as well as those into and out of Level 3, of the fair value hierarchy. Transfers into a level must be disclosed separately from transfers out of the level. Entities are required to judge the significance of transfers based on earnings and total assets or liabilities or, when changes in fair value are recognized in other comprehensive income, on total equity;

- Entities must also disclose and consistently follow their policy for when to recognize transfers into and out of the levels, which might be, for example, on the date of the event resulting in the transfer or at the beginning or end of the reporting period;

- Entities must separately present gross information about purchases, sales, issuances, and settlements in the reconciliation disclosure of Level 3 measurements, which are measurements requiring the use of significant unobservable inputs;

- For Level 2 and Level 3 measurements, an entity must disclose information about inputs and valuation techniques used in both recurring and nonrecurring fair value measurements. If a valuation technique changes, for example, from a market approach to an income approach, an entity must disclose the change and the reason for it. The amendments include implementation guidance on disclosures of valuation techniques and inputs; and

- Fair value measurement disclosures must be presented by class of assets and liabilities. Identifying appropriate classes requires judgment, and will often require the disaggregation of assets or liabilities included within a line item on the financial statements. An entity must determine the appropriate classes requiring disclosure based on the nature and risks of the assets and liabilities, their classification in the fair value hierarchy, and the level of disaggregated information required by other U.S. GAAP for specific assets and liabilities, such as derivatives.

The amended guidance does not include the sensitivity disclosures, as had been proposed.

The amended guidance is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disaggregation requirement for the reconciliation disclosure of Level 3 measurements, which is effective for fiscal years beginning after December 15, 2010 and for interim periods within those years. We adopted the guidance effective December 31, 2009, and the adoption did not have a significant impact on our consolidated financial statements. We have made all required disclosures.

Item 7A. *Quantitative and Qualitative Disclosure About Market Risk*

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at

December 31, 2009, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and to a lesser extent our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future. In this manner, we reduce credit risk.

Commodity price risk. We are exposed to market risk as the prices of oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing net income and the value of our common stock. An average increase in the commodity price of $10.00 per barrel of oil and $1.00 per MMBtu for natural gas from the commodity prices at December 31, 2009, would have increased the net unrealized loss on our commodity price risk management contracts by approximately $85.0 million.

At December 31, 2009, we had (i) an oil price collar and oil price swaps that settle on a monthly basis covering future oil production from January 1, 2010 through December 31, 2012 and (ii) a natural gas price swap, natural gas price collars and natural gas basis swaps covering future natural gas production from January 1, 2010 to December 31, 2011, see Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on the commodity derivative contracts. The average NYMEX oil futures price and average NYMEX natural gas futures prices for the year ended December 31, 2009, was $61.95 per Bbl and $4.16 per MMBtu, respectively. At February 24, 2010, the NYMEX oil futures price and NYMEX natural gas futures price were $80.00 per Bbl and $4.82 per MMBtu, respectively. A decrease in oil and natural gas prices, would decrease the fair value liability of our commodity derivative contracts from their recorded balance at December 31, 2009. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential decrease in our fair value liability would be recorded in earnings as an unrealized gain. However, an increase in the average NYMEX oil and natural gas futures price above those at December 31, 2009, would result in an increase in our fair value liability and be recorded as an unrealized loss in earnings. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base.

At December 31, 2009, we had interest rate swaps on $300 million of notional principal that fixed the LIBOR interest rate (not including the interest rate margins discussed above) at 1.90 percent for the three years beginning in May 2009. An average decrease in future interest rates of 25 basis points from the future rate at December 31, 2009, would have decreased our net unrealized value on our interest rate risk management contracts by approximately $1.8 million.

We had total indebtedness of $550.0 million outstanding under our credit facility at December 31, 2009. The impact of a 1 percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $5.5 million.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during 2009. During 2009, we were party to commodity and interest rate derivative instruments. See Note I of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2009:

	Derivative Instruments Net Assets (Liabilities)(a)		
	Commodities	Interest Rate	Total
		(In thousands)	
Fair value of contracts outstanding at December 31, 2008	$ 173,523	$(1,083)	$ 172,440
Changes in fair values(b)	(152,104)	(4,753)	(156,857)
Contract maturities	(85,751)	3,335	(82,416)
Fair value of contracts outstanding at December 31, 2009	$ (64,332)	$(2,501)	$ (66,833)

(a) Represents the fair values of open derivative contracts subject to market risk.

(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements and supplementary financial data are included in this report beginning on page F-1.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

We had no changes in, and no disagreements with our accountants, on accounting and financial disclosure.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2009 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2009, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework", issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting at December 31, 2009.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2009. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2009, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Concho Resources Inc.

We have audited Concho Resources Inc.'s (a Delaware Corporation) internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Concho Resources Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Concho Resources Inc.'s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Concho Resources Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Concho Resources Inc. and subsidiaries as of December 31, 2009 and 2008 and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2009, and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP
Tulsa, Oklahoma
February 26, 2010

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2009.

Item 11. *Executive Compensation*

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2009.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Equity Compensation Plans

At December 31, 2009, a total of 5,850,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. You can find descriptions of our stock incentive plan under Note G of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Plan Category	(1) Number of Securities to be Issued Upon Exercise of Outstanding Options	(2) Weighted Average Exercise Price of Outstanding Options	(3) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (1))
Equity compensation plan approved by security holders(a)	2,156,503	$14.11	1,581,226
Equity compensation plan not approved by security holders(b)	—	$ —	—
Total	2,156,503		1,581,226

(a) 2006 Stock Incentive Plan. See Note G of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) None.

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2009.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2009.

Item 14. *Principal Accounting Fees and Services*

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2009.

PART IV

Item 15. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K*

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements of ours are included in "Financial Statements and Supplementary Data:"

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2009 and 2008

Consolidated Statements of Operations for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Statements of Cash Flows for the Years Ended December 31, 2009, 2008 and 2007

Notes to Consolidated Financial Statements

Unaudited Supplementary Information

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the "Index to Exhibits" attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit Number	Exhibit
2.1	Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc., James C. Henry and Paula Henry, Henry Securities Ltd., Henchild LLC, Henry Family Investment Group, Henry Holding LP, Henry Energy LP, Aguasal Holding, HELP Investment LLC, Henry Capital LLC, Henry Operating LLC, Henry Petroleum LP, Quail Ranch LLC, Aguasal Management LLC, and Aguasal LP (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
2.2	Purchase and Sale Agreement, dated November 20, 2009, between Terrace Petroleum Corporation, et al., as Seller, and COG Operating LLC, as Buyer, (filed as Exhibit 2.1 to the Company's Current Report of Form 8-K on November 25, 2009, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on August 6, 2007, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Concho Resources Inc., as amended March 25, 2008 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on March 26, 2008, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A on July 5, 2007, and incorporated herein by reference).
4.2	Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).

Exhibit Number	Exhibit
4.3	First Supplemental Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
4.4	Form of 8.625% Senior Notes due 2017 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
10.1	Form of Drilling Agreement with Silver Oak Drilling, LLC (filed as Exhibit 10.4 to the Company's Registration Statement on Form S-1/A on July 5, 2007, and incorporated herein by reference).
10.2	Salt Water Disposal System Ownership and Operating Agreement dated February 24, 2006, among COG Operating LLC, Chase Oil Corporation, Caza Energy LLC and Mack Energy Corporation (filed as Exhibit 10.5 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.3	Software License Agreement dated March 2, 2006, between Enertia Software Systems and Concho Resources Inc. (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.4	Transfer of Operating Rights (Sublease) in a Lease for Oil and Gas for Valhalla properties (filed as Exhibit 10.8 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.5	Business Opportunities Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.6	Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.7**	Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.8**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.9**	Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.10**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.11**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.12**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.13**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.14**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.15**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and David W. Copeland (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.16**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

Exhibit Number	Exhibit
10.17**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.7 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.18**(a)	Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud.
10.19**	Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.20**	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.21**	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.22**	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).
10.23**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Puckett (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).
10.24**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Giraud (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).
10.25**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Leach and Beal (filed as Exhibit 10.29 to the Company's Registration Statement on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.26**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Copeland, Kamradt, Thomas and Wright (filed as Exhibit 10.30 to the Company's Registration Statement on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.27**	Form of Amendment to Stock Option Award Agreement with executive officers related to the Pre-Combination Options (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.28**	Form of Amendment to Nonstatutory Stock Option Agreement with executive officers related to the June 2006 Options (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.29**	Form of Restricted Stock Agreement with executive officers related to the June 2006 Options (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.30**	Consulting Agreement dated June 9, 2009, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 12, 2009, and incorporated herein by reference).
10.31	Common Stock Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.32	Registration Rights Agreement, dated July 31, 2008, by and between Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
10.33	Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).

Exhibit Number	Exhibit
10.34	First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, to the Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on April 9, 2009, and incorporated herein by reference).
10.35	Limited Consent and Waiver, dated September 4, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
12.1(a)	Ratio of Earnings to Fixed Charges and Earnings to Fixed Charges and Preferred Stock Dividends
21.1(a)	Subsidiaries of Concho Resources Inc.
23.1(a)	Consent of Grant Thornton LLP
23.2(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3(a)	Netherland, Sewell & Associates, Inc. Reserve Report
23.4(a)	Consent of Cawley, Gillespie & Associates, Inc.
23.5(a)	Cawley, Gillespie & Associates, Inc. Reserve Report
31.1(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or arrangement.

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.
Boe	One barrel of crude oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.
Bcfe	One billion cubic feet of natural gas equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.
Basin	A large natural depression on the earth's surface in which sediments accumulate.
Development wells	Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.
Exploratory wells	Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
GAAP	Generally accepted accounting principles in the United States of America.
Gross wells	The number of wells in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.
Infill wells	Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.
LIBOR	London Interbank Offered Rate, which is a market rate of interest.
MBbl	One thousand barrels of crude oil, condensate or natural gas liquids.
MBoe	One thousand Boe.
Mcf	One thousand cubic feet of natural gas.
MMBbl	One million barrels of crude oil, condensate or natural gas liquids.
MMBoe	One million Boe.
MMBtu	One million British thermal units.

MMcf	One million cubic feet of natural gas.
NYMEX	The New York Mercantile Exchange.
NYSE	The New York Stock Exchange.
Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.
Net wells	The total of fractional working interests owned in gross wells.
PV-10	When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent.
Primary recovery	The period of production in which oil and natural gas is produced from its reservoir through the wellbore without enhanced recovery technologies, such as water flooding or natural gas injection.
Productive wells	Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.
Proved developed reserves	Has the meaning given to such term in Release No. 33-8995: *Modernization of Oil and Gas Reporting*, which defines proved reserves as: Proved developed reserves are reserves of any category that can be expected to be recovered: (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) Through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well. Supplemental definitions from the 2007 Petroleum Resources Management System: Proved Developed Producing Reserves — Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation. Proved Developed Non-Producing Reserves — Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional

completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves

Has the meaning given to such term in Release No. 33-8995: *Modernization of Oil and Gas Reporting*, which defines proved reserves as:

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

    (A) The area identified by drilling and limited by fluid contacts, if any, and

    (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

    (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

    (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves

Has the meaning given to such term in Release No. 33-8995: *Modernization of Oil and Gas Reporting*, which defines proved reserves as:

Proved undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Recompletion

The addition of production from another interval or formation in an existing wellbore.

Reservoir

A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.

SEC

The United States Securities and Exchange Commission.

Seismic survey

Also known as a seismograph survey, is a survey of an area by means of an instrument which records the travel time of the vibrations of the earth. By recording the time interval between the source of the shock wave and the reflected or refracted shock waves from various formations, geophysicists are better able to define the underground configurations.

Spacing

The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized measure

The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with Financial Accounting Standards Board guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage

Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore

The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.

Working interest

The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Workover

Operations on a producing well to restore or increase production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONCHO RESOURCES INC.

By /s/ Timothy A. Leach

Timothy A. Leach
Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)

Date: February 26, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)	February 26, 2010
/s/ DARIN G. HOLDERNESS Darin G. Holderness	Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 26, 2010
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 26, 2010
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 26, 2010
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 26, 2010
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 26, 2010
/s/ RAY M. POAGE Ray M. Poage	Director	February 26, 2010
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 26, 2010
/s/ A. WELLFORD TABOR A. Wellford Tabor	Director	February 26, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Concho Resources Inc.

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Concho Resources Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note B to the consolidated financial statements, on December 31, 2009, the Company adopted the new requirements for oil and gas reserve estimation.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Concho Resources Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 26, 2010

CONCHO RESOURCES INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except share and per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,234	$ 17,752
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	69,199	48,793
Joint operations and other	100,120	92,833
Related parties	216	314
Derivative instruments	1,309	113,149
Deferred income taxes	29,284	—
Prepaid costs and other	13,896	5,942
Total current assets	217,258	278,783
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	3,358,004	2,693,574
Accumulated depletion and depreciation	(517,421)	(306,990)
Total oil and natural gas properties, net	2,840,583	2,386,584
Other property and equipment, net	15,706	14,820
Total property and equipment, net	2,856,289	2,401,404
Deferred loan costs, net	20,676	15,701
Inventory	16,255	19,956
Intangible asset, net — operating rights	36,522	37,768
Noncurrent derivative instruments	23,614	61,157
Other assets	471	434
Total assets	$3,171,085	$2,815,203
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 15,443	$ 7,462
Related parties	291	312
Other current liabilities:		
Bank overdrafts	3,415	9,434
Revenue payable	31,069	22,286
Accrued and prepaid drilling costs	164,282	154,196
Derivative instruments	62,419	1,866
Deferred income taxes	—	37,205
Other current liabilities	60,095	38,057
Total current liabilities	337,014	270,818
Long-term debt	845,836	630,000
Noncurrent derivative instruments	29,337	—
Deferred income taxes	603,286	573,763
Asset retirement obligations and other long-term liabilities	20,184	15,468
Commitments and contingencies (Note K)		
Stockholders' equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 85,815,926 and 84,828,824 shares issued at December 31, 2009 and 2008, respectively	86	85
Additional paid-in capital	1,029,392	1,009,025
Retained earnings	306,367	316,169
Treasury stock, at cost; 12,380 and 3,142 shares at December 31, 2009 and 2008, respectively	(417)	(125)
Total stockholders' equity	1,335,428	1,325,154
Total liabilities and stockholders' equity	$3,171,085	$2,815,203

The accompanying notes are an integral part of these consolidated financial statements.

CONCHO RESOURCES INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Operating revenues:			
Oil sales	$425,361	$ 390,945	$195,596
Natural gas sales	119,086	142,844	98,737
Total operating revenues	544,447	533,789	294,333
Operating costs and expenses:			
Oil and natural gas production	108,118	91,234	54,267
Exploration and abandonments	10,660	38,468	29,098
Depreciation, depletion and amortization	206,143	123,912	76,779
Accretion of discount on asset retirement obligations	1,058	889	444
Impairments of long-lived assets	12,197	18,417	7,267
General and administrative (including non-cash stock-based compensation of $9,040, $5,223 and $3,841 for the years ended December 31, 2009, 2008 and 2007, respectively)	52,277	40,776	25,177
Bad debt expense	(1,035)	2,905	—
Contract drilling fees — stacked rigs	—	—	4,269
Ineffective portion of cash flow hedges	—	(1,336)	821
(Gain) loss on derivatives not designated as hedges	156,857	(249,870)	20,274
Total operating costs and expenses	546,275	65,395	218,396
Income (loss) from operations	(1,828)	468,394	75,937
Other income (expense):			
Interest expense	(28,292)	(29,039)	(36,042)
Other, net	(414)	1,432	1,484
Total other expense	(28,706)	(27,607)	(34,558)
Income (loss) before income taxes	(30,534)	440,787	41,379
Income tax benefit (expense)	20,732	(162,085)	(16,019)
Net income (loss)	(9,802)	278,702	25,360
Preferred stock dividends	—	—	(45)
Net income (loss) applicable to common shareholders	$ (9,802)	$ 278,702	$ 25,315
Basic earnings per share:			
Net income (loss) per share	$ (0.12)	$ 3.52	$ 0.39
Weighted average shares used in basic earnings per share	84,912	79,206	64,316
Diluted earnings per share:			
Net income (loss) per share	$ (0.12)	$ 3.46	$ 0.38
Weighted average shares used in diluted earnings per share	84,912	80,587	66,309

The accompanying notes are an integral part of these consolidated financial statements.

CONCHO RESOURCES INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Notes Receivable from Officers and Employees	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock		Total Stockholders' Equity
	Shares	Amount					Shares	Amount	
					(In thousands)				
BALANCE AT DECEMBER 31, 2006	59,093	$59	$ 575,389	$(12,858)	$ 12,152	$ 414	—	$ —	$ 575,156
Comprehensive income:									
Net income	—	—	—	—	25,360	—	—	—	25,360
Deferred hedge losses, net of taxes of $13,204	—	—	—	—	—	(20,579)	—	—	(20,579)
Net settlement losses included in earnings, net of taxes of $3,830	—	—	—	—	—	5,970	—	—	5,970
Total comprehensive income									10,751
Stock-based compensation for restricted stock	138	—	1,378	—	—	—	—	—	1,378
Cancellation of restricted stock	(2)	—	—	—	—	—	—	—	—
Stock-based compensation for stock options	—	—	2,463	—	—	—	—	—	2,463
Amendment of certain outstanding stock options due to 409A modification	83	—	(192)	—	—	—	—	—	(192)
Issuance of common stock for acquisition obligation	54	—	650	—	—	—	—	—	650
Net proceeds from initial public equity offering	16,466	17	172,692	—	—	—	—	—	172,709
Proceeds from notes receivable — officers and employees	—	—	—	12,830	—	—	—	—	12,830
Accrued interest — officer and employee notes	—	—	—	(302)	—	—	—	—	(302)
6% Series A preferred stock dividends	—	—	—	—	(45)	—	—	—	(45)
BALANCE AT DECEMBER 31, 2007	75,832	76	752,380	(330)	37,467	(14,195)	—	—	775,398
Comprehensive income:									
Net income	—	—	—	—	278,702	—	—	—	278,702
Deferred hedge losses, net of taxes of $3,121	—	—	—	—	—	(4,864)	—	—	(4,864)
Net settlement losses included in earnings, net of taxes of $12,228	—	—	—	—	—	19,059	—	—	19,059
Total comprehensive income									292,897
Issuance of common stock	8,303	8	242,418	—	—	—	—	—	242,426
Stock options exercised	612	1	5,390	—	—	—	—	—	5,391
Stock-based compensation for restricted stock	128	—	2,122	—	—	—	—	—	2,122
Cancellation of restricted stock	(46)	—	—	—	—	—	—	—	—
Stock-based compensation for stock options	—	—	3,101	—	—	—	—	—	3,101
Excess tax benefits related to stock-based compensation	—	—	3,614	—	—	—	—	—	3,614
Proceeds from notes receivable — employees	—	—	—	333	—	—	—	—	333
Accrued interest — employee notes	—	—	—	(3)	—	—	—	—	(3)
Purchase of treasury stock	—	—	—	—	—	—	3	(125)	(125)
BALANCE AT DECEMBER 31, 2008	84,829	85	1,009,025	—	316,169	—	3	(125)	1,325,154
Net loss and total comprehensive loss	—	—	—	—	(9,802)	—	—	—	(9,802)
Stock options exercised	695	1	6,115	—	—	—	—	—	6,116
Stock-based compensation for restricted stock	300	—	4,755	—	—	—	—	—	4,755
Cancellation of restricted stock	(8)	—	—	—	—	—	—	—	—
Stock-based compensation for stock options	—	—	4,285	—	—	—	—	—	4,285
Excess tax benefits related to stock-based compensation	—	—	5,212	—	—	—	—	—	5,212
Purchase of treasury stock	—	—	—	—	—	—	9	(292)	(292)
BALANCE AT DECEMBER 31, 2009	85,816	$86	$1,029,392	$ —	$306,367	$ —	12	$(417)	$1,335,428

The accompanying notes are an integral part of these consolidated financial statements.

CONCHO RESOURCES INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (9,802)	$ 278,702	$ 25,360
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	206,143	123,912	76,779
Impairments of long-lived assets	12,197	18,417	7,267
Accretion of discount on asset retirement obligations	1,058	889	444
Exploration and abandonments, including dry holes	6,997	35,328	25,009
Non-cash compensation expense	9,040	5,223	3,841
Bad debt expense	(1,035)	2,905	—
Deferred income taxes	(30,919)	153,484	13,716
(Gain) loss on sale of assets	114	(777)	(368)
Ineffective portion of cash flow hedges	—	(1,336)	821
(Gain) loss on derivatives not designated as hedges	156,857	(249,870)	20,274
Dedesignated cash flow hedges reclassified from accumulated other comprehensive income (loss)	—	696	(1,103)
Other non-cash items	3,870	6,517	3,376
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(26,217)	39,609	(5,759)
Prepaid costs and other	(7,952)	(5,542)	(169)
Inventory	4,117	(16,819)	(150)
Accounts payable	7,960	(25,234)	(3,493)
Revenue payable	8,118	7,074	4,593
Other current liabilities	19,000	18,219	(669)
Net cash provided by operating activities	359,546	391,397	169,769
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on oil and natural gas properties	(403,798)	(347,702)	(162,378)
Acquisition of oil and natural gas properties, businesses and other assets	(265,469)	(584,220)	(255)
Additions to other property and equipment	(4,396)	(8,808)	(2,813)
Proceeds from the sale of oil and natural gas properties and other assets	5,099	1,034	3,278
Settlements received from (paid on) derivatives not designated as hedges	82,416	(6,354)	1,815
Net cash used in investing activities	(586,148)	(946,050)	(160,353)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	1,158,650	767,800	300,200
Payments of long-term debt	(942,916)	(465,700)	(468,800)
Exercise of stock options	6,116	5,391	—
Excess tax benefit from stock-based compensation	5,212	3,614	—
Net proceeds from issuance of common stock	—	242,426	172,709
Payments of preferred stock dividends	—	—	(132)
Proceeds from repayment of officer and employee notes	—	333	12,830
Payments for loan origination costs	(8,667)	(15,541)	(2,572)
Purchase of treasury stock	(292)	(125)	—
Bank overdrafts	(6,019)	3,783	5,651
Net cash provided by financing activities	212,084	541,981	19,886
Net increase (decrease) in cash and cash equivalents	(14,518)	(12,672)	29,302
Cash and cash equivalents at beginning of period	17,752	30,424	1,122
Cash and cash equivalents at end of period	$ 3,234	$ 17,752	$ 30,424
SUPPLEMENTAL CASH FLOWS:			
Cash paid for interest and fees, net of $66, $1,233 and $2,647 capitalized interest	$ 14,862	$ 27,747	$ 41,036
Cash paid for income taxes	$ 7,299	$ 11,304	$ 2,050
NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Issuance of common stock in acquisition of oil and natural gas properties and other assets	$ —	$ —	$ 650
Deferred tax effect of acquired oil and natural gas properties	$ (835)	$ 206,497	$ (444)

The accompanying notes are an integral part of these consolidated financial statements.

Note A. *Organization and nature of operations*

Concho Resources Inc. (the "Company") is a Delaware corporation formed on February 22, 2006. The Company's principal business is the acquisition, development and exploration of oil and natural gas properties in the Permian Basin region of Southeast New Mexico and West Texas.

Note B. *Summary of significant accounting policies*

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its wholly-owned subsidiaries. All material intercompany balances and transactions have been eliminated.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, the asset retirement obligations, fair value of derivative financial instruments, purchase price allocations for business and oil and natural gas property acquisitions and fair value of stock-based compensation.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in a few financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately $1.9 million and $2.9 million at December 31, 2009 and 2008, respectively, and the Company did not write off any receivables against the allowance for doubtful accounts in 2009, 2008 or 2007.

Inventory. Inventory consists primarily of tubular goods that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market value, on a weighted average cost basis.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of $20.7 million and $15.7 million, net of accumulated amortization of $8.6 million and $4.9 million, at December 31, 2009 and December 31, 2008, respectively.

Future amortization expense of deferred loan costs at December 31, 2009 is as follows:

	Total (In thousands)
2010	$ 4,190
2011	4,266
2012	4,350
2013	3,021
2014	1,132
Thereafter	3,717
Total	$20,676

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized acquisition costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized exploratory drilling and development costs is based on the unit-of-production method using proved developed reserves on a field basis.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets for more than one year following the completion of drilling unless the exploratory well finds oil and natural gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well; and

(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is charged to exploration and abandonments expense. See Note C for additional information regarding the Company's suspended exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until such time as the related project is developed and proved reserves are established or impairment is determined. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. At December 31, 2009 and 2008 the Company had excluded $30.9 million and $27.8 million, respectively, of capitalized costs from depletion and had capitalized interest of $0.07 million, $1.2 million and $2.6 million, during 2009, 2008 and 2007, respectively.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. The Company recognized impairment expense of $11.8 million, $18.4 million and $7.3 million during the years ended December 31, 2009, 2008 and 2007, respectively, related to its proved oil and natural gas properties.

Unproved oil and natural gas properties are each periodically assessed for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. During the years ended December 31, 2009, 2008 and 2007, the Company recognized expense of $5.1 million, $31.6 million and $3.1 million, respectively, related to abandoned prospects, which is included in exploration and abandonments in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, vehicles, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 15 years.

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition, see Note D. The gross operating rights of approximately $38.7 million and related accumulated amortization of $2.2 million, which have no residual value, are amortized over the estimated economic life of approximately 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. Amortization expense for the years ended December 31, 2009 and 2008 was approximately $1.6 million and $0.6 million, respectively. The following table reflects the estimated aggregate amortization expense for each of the periods presented below:

	(In thousands)
2010	$ 1,549
2011	1,549
2012	1,549
2013	1,549
2014	1,549
Thereafter	28,777
Total	$36,522

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2009 and 2008, the Company has accrued approximately $0.8 million and $0.4 million, respectively, related to environmental liabilities associated with certain properties in the state of New Mexico. During the years ended December 31, 2009, 2008 and 2007, the Company has recognized environmental charges of $2.3 million, $0.5 million and $0.2 million, respectively.

Oil and natural gas sales and imbalances. Oil and natural gas revenues are recorded at the time of delivery of such products to pipelines for the account of the purchaser or at the time of physical transfer of such products to the purchaser. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's share of actual proceeds from the oil and natural gas sold to purchasers. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production "in-kind" and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance.

The following table reflects the Company's natural gas imbalance positions at December 31, 2009 and 2008 as well as amounts reflected in oil and natural gas production expense for the years ended December 31, 2009 and 2008:

	December 31,	
	2009	2008
	(Dollars in thousands)	
Natural gas imbalance liability (included in asset retirement obligations and other long-term liabilities)	$ 533	$ 472
Overtake position (Mcf)	101,278	85,698
Natural gas imbalance receivable (included in other assets)	$ 444	$ 406
Undertake position (Mcf)	98,584	90,321

	Years Ended December 31,	
	2009	2008
	(Dollars in thousands)	
Value of net overtake (undertake) arising during the year increasing (decreasing) oil and natural gas production expense	$ 23	$ (189)
Net overtake (undertake) position arising during the year (Mcf)	7,317	(19,269)

Derivative instruments and hedging. The Company recognizes all derivative instruments as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists.

The Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a "fair value hedge") or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a "cash flow hedge"). Special accounting for qualifying hedges allows the effective portion of a derivative instrument's gains and losses to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate and assess the effectiveness of the transactions that receive hedge accounting treatment. Both at the inception of a hedge and on an ongoing basis, a hedge must be expected to be highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. If the Company determines that a derivative instrument is no longer highly effective as a hedge, it discontinues hedge accounting prospectively and future changes in the fair value of the derivative are recognized in current earnings. The amount already reflected in accumulated other comprehensive (loss) income ("AOCI") remains there until the hedged item affects earnings or it is probable that the hedged item will not occur by the end of the originally specified time period or within two months thereafter. The Company assesses and measures hedge effectiveness at the end of each quarter.

Changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities or firm commitments, through earnings. Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in AOCI and reclassified into earnings in the period in which the hedged item affects earnings. Ineffective portions of a derivative instrument's change in fair value are immediately recognized in earnings. Derivative instruments that do not qualify, or cease to qualify, as hedges must be adjusted to fair value and the adjustments are recorded through earnings. The Company did not have any derivatives designated as fair value or cash flow hedges during the year ended December 31, 2009.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depreciation of the asset. Changes in the liability due to passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $11.4 million, $4.9 million and $1.1 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Stock-based compensation. From time to time, the Company exchanges its equity instruments for services and incurs liabilities that are based on the fair value of the Company's equity instruments or that may be settled by the issuance of those equity instruments in exchange for the services. The cost of the services received in exchange for equity instruments, including stock options, is measured based on the grant-date fair value of those instruments. That cost is recognized as compensation expense over the requisite service period (generally the vesting period). Generally, no compensation cost is recognized for equity instruments that do not vest.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax positions will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company had no uncertain tax positions that required recognition in the consolidated financial statements at December 31, 2009 and 2008. Any interest or penalties would be recognized as a component of income tax expense.

Recent accounting pronouncements. In June 2009, the Financial Accounting Standards Board ("FASB" or the "Board") issued the Accounting Standards Codification (the "Codification" or "ASC") which has become the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in accordance with Generally Accepted Accounting Principles ("GAAP"). All existing accounting standard documents are superseded by the Codification and any accounting literature not included in the Codification will not be authoritative. However, rules and interpretive releases of the United States Securities and Exchange Commission (the "SEC") issued under the authority of federal securities laws will continue to be the source of authoritative generally accepted accounting principles for SEC registrants. Effective September 30, 2009, there are no more references made to the superseded FASB standards in the Company's consolidated financial statements. The Codification does not change or alter existing GAAP and, therefore, did not have an impact on the Company's financial position, results of operations or cash flows.

Business combinations. In December 2007, the FASB issued a revision to the existing business combinations guidance. The guidance establishes principles and requirements for how an acquirer recognizes and measures the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. It also establishes disclosure requirements that enable users to evaluate the nature and financial effects of the business combination. The revised standard was effective for acquisitions occurring in an entity's fiscal year beginning after December 15, 2008. The Company adopted the standard effective January 1, 2009, and accounts for all its business combinations using this standard and discloses all required information.

Fair value. In August 2009, the FASB issued an update to the Fair Value Topic of the Codification. The FASB issued the update because some entities have expressed concern that there may be a lack of observable market information to measure the fair value of a liability. The topic is effective for the first reporting period beginning after August 28, 2009, with earlier application permitted. The guidance provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. In such circumstances, the topic specifies that a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Examples of the alternative valuation methods include using a present value technique or a market approach, which is based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. The guidance also states that when estimating the fair value of a liability, a reporting entity is not required to include a separate input or adjustments to other inputs relating to the existence of a restriction that prevents the transfer of the liability. The Company adopted the topic effective September 30, 2009, and the adoption did not have a significant impact on the Company's consolidated financial statements.

Oil and natural gas. In September 2009, the FASB issued an update to the Oil and Gas Topic, which makes a technical correction related to an SEC Observer comment, regarding the accounting and disclosures for natural gas balancing arrangements. The topic amends prior guidance because the SEC staff has not taken a position on whether the entitlements method or sales method is preferable for natural gas-balancing arrangements that do not meet the definition of a derivative.

With the entitlements method, sales revenue is recognized to the extent of each well partner's proportionate share of natural gas sold regardless of which partner sold the natural gas. Under the sales method, sales revenue is recognized for all natural gas sold by a partner even if the partner's ownership is less than 100 percent of the natural gas sold.

The Oil and Gas Topic update included an instruction that public companies must account for all significant natural gas imbalances consistently using one accounting method. Both the method and any significant amount of imbalances in units and value should be disclosed in regulatory filings. The Company currently accounts for all natural gas balances under the sales method and makes all required disclosures.

Reserve estimation. In January 2010, the FASB issued an update to the Oil and Gas Topic, which aligns the oil and natural gas reserve estimation and disclosure requirements with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements* (the "Final Rule"). The Final Rule was issued on December 31, 2008. The Final Rule is intended to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves, which should help investors evaluate the relative value of oil and natural gas companies.

The Final Rule permits the use of new technologies to determine proved reserves estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Final Rule will also allow, but not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Final Rule became effective for fiscal years ending on or after December 31, 2009. The Company adopted the ruling effective December 31, 2009, which had the effect of adding 13.6 MMBoe of proved reserves. The Company's fourth quarter 2009 depletion and impairment calculations were based upon proved reserves that were determined using the new reserve rules, whereas depletion and impairment calculations in previous quarters within 2009 were based on the prior SEC methodology. See reserves information in the Unaudited Supplementary Data disclosures.

Fair value. In January 2010, the FASB issued an update to the Fair Value Topic, which enhances the usefulness of fair value measurements. The amended guidance requires both the disaggregation of information in certain existing disclosures, as well as the inclusion of more robust disclosures about valuation techniques and inputs to recurring and nonrecurring fair value measurements.

The topic amends the disclosures about fair value measurements in the Fair Value Topic as follows:

- Entities must disclose the amounts of, and reasons for, significant transfers between Level 1 and Level 2, as well as those into and out of Level 3, of the fair value hierarchy. Transfers into a level must be disclosed separately from transfers out of the level. Entities are required to judge the significance of transfers based on earnings and total assets or liabilities or, when changes in fair value are recognized in other comprehensive income, on total equity;
- Entities must also disclose and consistently follow their policy for when to recognize transfers into and out of the levels, which might be, for example, on the date of the event resulting in the transfer or at the beginning or end of the reporting period;
- Entities must separately present gross information about purchases, sales, issuances, and settlements in the reconciliation disclosure of Level 3 measurements, which are measurements requiring the use of significant unobservable inputs;
- For Level 2 and Level 3 measurements, an entity must disclose information about inputs and valuation techniques used in both recurring and nonrecurring fair value measurements. If a valuation technique changes, for example, from a market approach to an income approach, an entity must disclose the change and the reason for it. The amendments include implementation guidance on disclosures of valuation techniques and inputs; and
- Fair value measurement disclosures must be presented by class of assets and liabilities. Identifying appropriate classes requires judgment, and will often require the disaggregation of assets or liabilities included within a line item on the financial statements. An entity must determine the appropriate classes requiring disclosure based on the nature and risks of the assets and liabilities, their classification in the fair value hierarchy, and the level of disaggregated information required by other U.S. GAAP for specific assets and liabilities, such as derivatives.

The amended guidance does not include the sensitivity disclosures, as had been proposed.

The amended guidance is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disaggregation requirement for the reconciliation disclosure of Level 3 measurements, which is effective for fiscal years beginning after December 15, 2010 and for interim periods within those years. The Company adopted the guidance effective December 31, 2009, and the adoption did not have a significant impact on the Company's consolidated financial statements. The Company has made all required disclosures.

Various topics. In February 2010, the FASB issued an update to various topics, which eliminated outdated provisions and inconsistencies in the Codification, and clarified certain guidance to reflect the Board's original intent. The update is effective for the first reporting period, including interim periods, beginning after issuance of the update, except for the amendments affecting embedded derivatives and reorganizations. In addition to amending the Codification, the FASB made corresponding changes to the legacy accounting literature to facilitate historical research. These changes are included in an appendix to the update. The Company adopted the update effective January 1, 2010, and the adoption did not have a significant impact on the Company's consolidated financial statements.

Note C. *Exploratory well costs*

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in unproved properties in the consolidated balance sheets. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Beginning capitalized exploratory well costs	$ 25,553	$ 21,056	$ 26,503
Additions to exploratory well costs pending the determination of proved reserves	135,656	25,621	97,368
Reclassifications due to determination of proved reserves	(152,200)	(18,327)	(95,869)
Exploratory well costs charged to expense	(341)	(2,797)	(6,946)
Ending capitalized exploratory well costs	$ 8,668	$ 25,553	$ 21,056

The following table provides an aging at December 31, 2009 and 2008 of capitalized exploratory well costs based on the date the drilling was completed:

	December 31,	
	2009	2008
	(In thousands)	
Wells in drilling progress	$1,767	$ 7,765
Capitalized exploratory well costs that have been capitalized for a period of one year or less	6,901	17,788
Capitalized exploratory well costs that have been capitalized for a period greater than one year	—	—
Total capitalized exploratory well costs	$8,668	$25,553

At December 31, 2009, the Company had 18 gross exploratory wells either drilling or waiting on results from completion. There are 6 wells in the Texas Permian area, 5 wells in the New Mexico Permian area, 6 wells in our Bakken/Three Forks emerging play and 1 well in the Lower Abo emerging play.

Note D. *Acquisitions and business combinations*

Wolfberry acquisitions. In December 2009, the Company closed two significant acquisitions of interests in producing and non-producing assets in the Wolfberry play in the Permian Basin for approximately $260 million, subject to usual and customary post-closing adjustments (the "Wolfberry Acquisitions"). The Wolfberry

Acquisitions were primarily funded with borrowings under the Company's credit facility, see Note J. The Company's 2009 results of operations do not include any production, revenues or costs from the Wolfberry Acquisitions.

The following tables represent the allocation of the total purchase price of the Wolfberry Acquisitions to the acquired assets and liabilities. The allocation represents the fair values assigned to each of the assets acquired and liabilities assumed:

	(In thousands)
Fair value of the Wolfberry Acquisitions' net assets:	
Proved oil and natural gas properties	$203,280
Unproved oil and natural gas properties	57,573
Total assets acquired	260,853
Asset retirement obligations	(464)
Net purchase price	$260,389

Henry Entities acquisition. On July 31, 2008, the Company closed its acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (which we refer to as "Henry" or the "Henry Entities") and additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, the Company acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. The assets acquired in the Henry Entities acquisition are referred to as the "Henry Properties." The Company paid $583.7 million in cash for the Henry Properties acquisition.

The cash paid for the Henry Properties acquisition was funded with (i) borrowings under the Company's credit facility, see Note J, and (ii) proceeds from a private placement of approximately 8.3 million shares of the Company's common stock, see Note F.

The Henry Properties acquisition was accounted for using the purchase method of accounting for business combinations. Under the purchase method of accounting, the Company recorded the Henry Properties' assets and liabilities at fair value. The purchase price of the acquired Henry Properties' net assets is based on the total value of the cash consideration.

The following tables represent the allocation of the total purchase price of the Henry Properties to the acquired assets and liabilities of the Henry Properties and the consideration paid for the Henry Properties. The allocation represents the fair values assigned to each of the assets acquired and liabilities assumed:

	(In thousands)
Fair value of Henry Properties' net assets:	
Current assets, net of cash acquired of $19,049(a)	$ 86,005
Proved oil and natural gas properties	593,634
Unproved oil and natural gas properties	233,527
Other long-term assets	7,392
Intangible assets — operating rights	38,717
Total assets acquired	959,275

	(In thousands)
Current liabilities	(114,394)
Asset retirement obligations and other long-term liabilities	(7,529)
Noncurrent derivative liabilities	(39,037)
Deferred tax liability	(214,640)
Total liabilities assumed	(375,600)
Net purchase price	$ 583,675
Consideration paid for Henry Properties' net assets:	
Cash consideration paid, net of cash acquired of $19,049	$ 578,025
Acquisition costs(b)	5,650
Total purchase price	$ 583,675

(a) Includes a deferred tax asset of approximately $9.0 million.

(b) Acquisition costs include legal and accounting fees, advisory fees and other acquisition-related costs.

The following unaudited pro forma combined condensed financial data for the year ended December 31, 2008 was derived from the historical financial statements of the Company and Henry Properties giving effect to the acquisition as if it had occurred on January 1, 2008. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Henry Properties acquisition taken place as of the date indicated and is not intended to be a projection of future results.

	Year Ended December 31, 2008
	(In thousands, except per share data) (Unaudited)
Operating revenues	$629,214
Net income applicable to common shareholders	$257,540
Earnings per common share:	
Basic	$ 2.94
Diluted	$ 2.90

Note E. ***Asset retirement obligations***

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The following table summarizes the Company's asset retirement obligation transactions during the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Asset retirement obligations, beginning of period	$16,809	$ 9,418	$8,700
Liabilities incurred from new wells	1,526	1,197	471
Liabilities assumed in acquisitions	488	7,062	—
Accretion expense	1,058	889	444
Disposition of wells	(223)	—	—
Liabilities settled upon plugging and abandoning wells	(1,255)	—	(26)
Revision of estimates	4,351	(1,757)	(171)
Asset retirement obligations, end of period	$22,754	$16,809	$9,418

Note F. *Stockholders' equity and treasury stock*

Common stock private placement. On June 5, 2008, the Company entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of the Company's common stock in a private placement (the "Private Placement") contemporaneous with the closing of the Henry Properties acquisition. On July 31, 2008, the Company issued 8,302,894 shares of its common stock at $30.11 per share. The Private Placement resulted in net proceeds of approximately $242.4 million to the Company, after payment of approximately $7.6 million for the fee paid to the placement agent.

Initial public offering. On August 7, 2007, the Company completed an initial public offering (the "IPO") of its common stock. The Company sold 13,332,851 shares of its common stock in the IPO and certain shareholders, including its executive officers and certain members of Chase Oil Corporation ("Chase Oil"), Caza Energy LLC ("Caza") and certain other parties thereto (collectively the "Chase Group"), sold 7,554,256 shares of the Company's common stock at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.5 million, the Company received net proceeds of approximately $139.2 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,133,066 additional shares of the Company's common stock. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.2 million, the Company received net proceeds of approximately $33.8 million. The aggregate net proceeds of approximately $173.0 million received by the Company at closing on August 7, 2007 and August 9, 2007 were utilized to reduce bank debt.

Secondary public offering. On December 19, 2007, the Company completed a secondary public offering of 11,845,000 shares of the Company's common stock, which was sold by certain of the Company's stockholders, including certain members of the Chase Group. The Chase Group sold 10,194,732 shares of the Company's common stock in the aggregate and certain other stockholders of the Company sold 1,650,268 shares of the Company's common stock in the aggregate, including one of the Company's executive officers who sold 45,000 shares of the Company's common stock. Chase Oil granted the underwriters an option to purchase up to 1,776,615 additional shares of the Company's common stock to cover over-allotments, which was fully exercised on December 19, 2007. The Company did not receive any proceeds from the sale of the Company's common stock in this secondary offering.

Treasury stock. The restrictions on certain restricted stock awards issued to certain of the Company's executive officers lapsed during the years ended December 31, 2009 and 2008. Immediately upon the lapse of restrictions, these executive officers became liable for income taxes on the value of such shares. In accordance with the Company's 2006 Stock Incentive Plan and the applicable restricted stock award agreements, some of such officers elected to deliver shares of the Company's common stock to the Company in exchange for cash used to satisfy such tax liability. In total, at December 31, 2009 and 2008, the Company had acquired 12,380 and 3,142 shares, respectively, that are held as treasury stock in the approximate amount of $417,000 and $125,000, respectively.

Note G. *Incentive plans*

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees and maintains certain other acquired plans. The Company matches 100 percent of employee contributions, not to exceed 6 percent of the employee's annual salary. The Company contributions to the plans for the years ended December 31, 2009, 2008 and 2007 were approximately $1.0 million, $1.2 million, and $0.4 million, respectively.

Stock incentive plan. The Company's 2006 Stock Incentive Plan (together with applicable option agreements and restricted stock agreements, the "Plan") provides for granting stock options and restricted stock awards to employees and individuals associated with the Company. The following table shows the number of awards available under the Company's Plan at December 31, 2009:

	Number of Common Shares
Approved and authorized awards	5,850,000
Stock option grants, net of forfeitures	(3,463,720)
Restricted stock grants, net of forfeitures	(805,054)
Awards available for future grant	1,581,226

Restricted stock awards. All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock awards for the years ended December 31, 2009, 2008 and 2007 is presented below:

	Number of Restricted Shares	Grant Date Fair Value Per Share
Restricted stock:		
Outstanding at January 1, 2007	212,216	
Shares granted	220,995	$ 9.22
Shares cancelled / forteited	(1,662)	
Lapse of restrictions	(60,000)	
Outstanding at December 31, 2007	371,549	
Shares granted	128,001	$32.13
Shares cancelled / forteited	(46,741)	
Lapse of restrictions	(45,458)	
Outstanding at December 31, 2008	407,351	
Shares granted	300,119	$27.10
Shares cancelled / forteited	(7,874)	
Lapse of restrictions	(202,339)	
Outstanding at December 31, 2009	497,257	

The following table summarizes information about stock-based compensation for the Company's restricted stock awards for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31, 2009	2008	2007
	(In thousands)		
Grant date fair value for awards during the period:			
Employee grants	$5,187	$2,693	$1,633
Officer and director grants(a)	3,256	1,420	404
Total	$8,443	$4,113	$2,037
Stock-based compensation expense from restricted stock:			
Employee grants	$3,003	$1,498	$ 993
Officer and director grants(a)	1,752	624	385
Total	$4,755	$2,122	$1,378
Income taxes and other information:			
Income tax benefit related to restricted stock	$1,790	$ 808	$ 533
Deductions in current taxable income related to restricted stock	$5,458	$1,234	$ —

(a) The year ended December 31, 2009 includes effects of modifications to certain stock-based awards, see further discussion below.

Stock option awards. A summary of the Company's stock option activity under the Plan for the years ended December 31, 2009, 2008 and 2007 is presented below:

	2009 Number of Options	2009 Weighted Average Exercise Price	2008 Number of Options	2008 Weighted Average Exercise Price	2007 Number of Options	2007 Weighted Average Exercise Price
Stock options:						
Outstanding at beginning of period	2,731,324	$12.46	3,011,722	$ 9.71	2,797,997	$ 8.93
Options granted	120,301	$20.75	607,555	$23.54	215,000	$12.85
Options forfeited	(265)	$ 8.00	(275,593)	$14.96	(1,275)	$ 8.00
Options exercised	(694,857)	$ 8.80	(612,360)	$ 8.80	—	$ —
Outstanding at end of period	2,156,503	$14.11	2,731,324	$12.46	3,011,722	$ 9.71
Vested at end of period	1,460,588	$11.00	1,567,389	$ 9.18	2,063,499	$ 8.79
Exercisable at end of period	635,861	$14.67	517,019	$11.16	508,462	$10.58

The following table summarizes information about the Company's vested and exercisable stock options outstanding at December 31, 2009, 2008 and 2007:

		Number Vested and Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value (In thousands)
Vested options:					
December 31, 2009:					
Exercise price	$ 8.00	960,669	2.06 years	$ 8.00	$35,449
Exercise price	$12.00	116,728	4.45 years	$12.00	3,840
Exercise price	$14.80	245,000	6.73 years	$14.80	7,374
Exercise price	$21.86	104,625	8.18 years	$21.86	2,411
Exercise price	$31.81	33,566	8.50 years	$31.81	440
		1,460,588	3.62 years	$11.00	$49,514
Exercisable options:					
December 31, 2009:					
Exercise price	$ 8.00	171,903	4.62 years	$ 8.00	$ 6,343
Exercise price	$12.00	80,767	5.76 years	$12.00	2,657
Exercise price	$14.80	245,000	6.73 years	$14.80	7,374
Exercise price	$21.86	104,625	8.18 years	$21.86	2,411
Exercise price	$31.81	33,566	8.50 years	$31.81	440
		635,861	6.37 years	$14.67	$19,225
Vested options:					
December 31, 2008:					
Exercise price	$ 8.00	1,232,647	2.58 years	$ 8.00	$18,268
Exercise price	$12.00	143,492	4.99 years	$12.00	1,553
Exercise price	$14.68	191,250	7.78 years	$14.68	1,556
		1,567,389	3.43 years	$ 9.18	$21,377
Exercisable options:					
December 31, 2008:					
Exercise price	$ 8.00	236,227	5.62 years	$ 8.00	$ 3,501
Exercise price	$12.00	89,542	6.78 years	$12.00	969
Exercise price	$14.68	191,250	7.78 years	$14.68	1,556
		517,019	6.62 years	$11.16	$ 6,026
Vested options:					
December 31, 2007:					
Exercise price	$ 8.00	1,753,819	3.15 years	$ 8.00	$22,116
Exercise price	$12.00	197,180	5.72 years	$12.00	1,698
Exercise price	$15.40	112,500	8.45 years	$15.40	586
		2,063,499	3.68 years	$ 8.79	$24,400

		Number Vested and Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value (In thousands)
Exercisable options:					
December 31, 2007:					
Exercise price	$ 8.00	275,685	6.62 years	$ 8.00	$ 3,476
Exercise price	$12.00	120,277	7.78 years	$12.00	1,036
Exercise price	$15.40	112,500	8.45 years	$15.40	586
		508,462	7.30 years	$10.58	$ 5,098

The following table summarizes information about stock-based compensation for options for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31, 2009	2008	2007
	(In thousands)		
Grant date fair value for awards during the period:			
Employee grants	$ 50	$ 580	$ 87
Officer and director grants(a)	4,923	5,675	1,921
Total	$ 4,973	$ 6,255	$2,008
Stock-based compensation expense from stock options:			
Employee grants	$ 258	$ 181	$ 17
Officer and director grants(a)	4,027	2,920	2,446
Total	$ 4,285	$ 3,101	$2,463
Income taxes and other information:			
Income tax benefit related to stock options	$ 1,614	$ 1,990	$ 953
Deductions in current taxable income related to stock options exercised	$14,414	$10,756	$ —

(a) The year ended December 31, 2009 includes effects of modifications to certain stock-based awards, see further discussion below.

In calculating the compensation expense for stock options granted during the years ended December 31, 2009, 2008 and 2007, the Company estimated the fair value of each grant using the Black-Scholes option-pricing model. Assumptions utilized in the model are shown below.

	2009	2008	2007
Risk-free interest rate	2.47%	3.18%	4.47%
Expected term (years)	6.25	6.21	6.25
Expected volatility	63.19%	38.88%	37.33%
Expected dividend yield	—	—	—

The Company used the simplified method that is accepted by the SEC staff to calculate the expected term for stock options granted during the years ended December 31, 2009, 2008 and 2007, since it did not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its shares of common stock have been publicly traded. Expected volatilities are based on a combination of historical and implied volatilities of comparable companies.

Modification of stock-based awards. David W. Copeland, the Company's former Vice President, General Counsel and Corporate Secretary, announced his intention to retire effective December 31, 2010. Mr. Copeland stepped down from such positions on November 5, 2009, but plans to remain with the Company as Senior Counsel through his planned retirement date of December 31, 2010. As part of Mr. Copeland's retirement agreement, all of Mr. Copeland's stock-based awards were modified to permit full vesting on his planned retirement date. As a result of this modification, the Company (i) recognized a reduction in stock-based compensation of approximately $5,000 during the year ended December 31, 2009 and (ii) will recognize additional stock-based compensation of approximately $0.4 million in future periods.

Steven L. Beal, the Company's former President and Chief Operating Officer, retired from such positions on June 30, 2009. Mr. Beal began serving as a consultant on July 1, 2009; see Note N. As part of the consulting agreement, certain of Mr. Beal's stock-based awards were modified to permit vesting and exercise under the original terms of the stock-based awards as if Mr. Beal was still an employee of the Company while he is performing consulting services for the Company. As a result of this modification, the Company (i) recognized approximately $0.8 million of stock-based compensation during the year ended December 31, 2009 and (ii) will recognize additional stock-based compensation of approximately $1.0 million in future periods.

On November 8, 2007, the compensation committee of the Company's board of directors authorized and approved amendments to certain outstanding agreements related to options to purchase the Company's common stock that were previously awarded to certain of the Company's executive officers and employees in order to amend such award agreements so that the subject stock option award would constitute deferred compensation that is compliant with Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), or exempt from the application of Section 409A. As the offer to amend outstanding stock option agreements previously issued to certain of the Company's employees may constitute a tender offer under the Securities Exchange Act of 1934, on November 8, 2007, the board of directors of the Company authorized commencement of a tender offer to amend the applicable outstanding stock option award agreements in the form approved by the compensation committee.

Generally, the amendments provide that the employee stock options, which had previously vested in connection with a past business combination, will become exercisable in 25 percent increments over a four year period beginning in 2008 and continuing through 2011 or upon the occurrence of certain specified events. Employees who decided to amend their stock option award agreement received a cash payment equal to $0.50 for each share of common stock subject to the amendment on January 2, 2008. The Company made aggregate cash payments of approximately $192,000 to such employees. The Company's affected executive officers received and accepted a similar offer to amend their stock option awards issued prior to a past business combination on substantially the same terms, except such officers were not offered the $0.50 per share payment.

In addition, the Company's named executive officers received stock option awards in June 2006 to purchase 450,000 shares of common stock, in the aggregate, at a purchase price of $12.00 per share. The Company subsequently determined that the fair market value of a share of common stock as of the date of the award was $15.40. As a result, the compensation committee of the Company's board of directors authorized and approved an amendment to these stock option award agreements pursuant to which the exercise price of such stock options would be increased from $12.00 per share to $15.40 per share. The Company agreed to issue to the executive officer an award of the number of shares of restricted stock equal to (i) the product of $3.40 and the number of shares of common stock subject to the stock option award, divided by (ii) the Fair Market Value of a share of common stock on the date of the award of restricted stock.

The Company has determined that its aggregate compensation expense resulting from these modifications of approximately $0.8 million would be recorded during the period from November 8, 2007 to December 31, 2007 and during the years ending December 31, 2008, 2009 and 2010.

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that are outstanding at December 31, 2009:

	Restricted Stock	Stock Options	Total
	(In thousands)		
2010	$4,449	$2,651	$ 7,100
2011	2,486	879	3,365
2012	783	184	967
2013	47	16	63
Total	$7,765	$3,730	$11,495

Note H. *Disclosures about fair value of financial instruments*

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

***Level 1*:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

***Level 2*:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company utilizes its counterparties' valuations to assess the reasonableness of its prices and valuation techniques.

***Level 3*:** Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). Level 3 instruments primarily include derivative instruments, such as commodity price collars and floors, as well as investments. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although the Company utilizes its counterparties' valuations to assess the reasonableness of our prices and valuation techniques, the Company does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety. The following table presents the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2009, for each of the fair value hierarchy levels:

	Fair Value Measurements at Reporting Date Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at December 31, 2009
		(In thousands)		
Assets:				
Commodity derivative price swap contracts	$—	$ 48,866	$ —	$ 48,866
Commodity derivative price collar contracts	—	—	134	134
Interest rate derivative swap contracts	—	1,369	—	1,369
	—	50,235	134	50,369
Liabilities:				
Commodity derivative price swap contracts	—	(103,610)	—	(103,610)
Commodity derivative basis swap contracts	—	(8,643)	—	(8,643)
Interest rate derivative swap contracts	—	(3,870)	—	(3,870)
Commodity derivative price collar contracts	—	—	(1,079)	(1,079)
	—	(116,123)	(1,079)	(117,202)
Net financial assets (liabilities)	$—	$ (65,888)	$ (945)	$ (66,833)

The following table sets forth a reconciliation of changes in the fair value of financial assets (liabilities) classified as Level 3 in the fair value hierarchy:

	(In thousands)
Balance at December 31, 2008	$ 49,562
Realized and unrealized losses	(6,804)
Settlements, net	(43,703)
Balance at December 31, 2009	$ (945)
Total losses for the period included in earnings attributable to the change in unrealized losses relating to assets (liabilities) still held at the reporting date	$(50,507)

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following table presents the carrying amounts and fair values of the Company's financial instruments at December 31, 2009 and 2008:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Assets:				
Derivative instruments	$ 24,923	$ 24,923	$174,306	$174,306
Liabilities:				
Derivative instruments	$ 91,756	$ 91,756	$ 1,866	$ 1,866
Credit facility	$550,000	$528,849	$630,000	$553,645
8.625% senior notes due 2017	$295,836	$315,000	$ —	$ —

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Credit facility. The fair value of the Company's credit facility is estimated by discounting the principal and interest payments at the Company's credit adjusted discount rate at the reporting date. The fair value at December 31, 2009 was approximately $528.8 million based on outstanding borrowings of $550.0 million and approximately $553.6 million at December 31, 2008 based on outstanding borrowings of $630 million.

Senior notes. The fair value of the Company's senior notes are based on quoted market prices.

Derivative instruments. The fair value of the Company's derivative instruments are estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table (i) summarizes the valuation of each of the Company's financial instruments by required pricing levels and (ii) summarizes the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at December 31, 2009 and 2008:

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value at December 31, 2009
	(In thousands)			
Assets(1)				
Current:(a)				
Commodity derivative price swap contracts	$—	$ 13,850	$ —	$ 13,850
Commodity derivative price collar contracts	—	—	134	134
	—	13,850	134	13,984
Noncurrent:(b)				
Commodity derivative price swap contracts	—	35,016	—	35,016
Interest rate derivative swap contracts	—	1,369	—	1,369
	—	36,385	—	36,385
Liabilities(1)				
Current:(a)				
Commodity derivative price swap contracts	—	(65,351)	—	(65,351)
Commodity derivative basis swap contracts	—	(5,254)	—	(5,254)
Interest rate derivative swap contracts	—	(3,870)	—	(3,870)
Commodity derivative price collar contracts	—	—	(619)	(619)
	—	(74,475)	(619)	(75,094)
Noncurrent:(b)				
Commodity derivative price swap contracts	—	(38,259)	—	(38,259)
Commodity derivative basis swap contracts	—	(3,389)	—	(3,389)
Commodity derivative price collar contracts	—	—	(460)	(460)
	—	(41,648)	(460)	(42,108)
Net financial assets (liabilities)	$—	$(65,888)	$(945)	$(66,833)
(a) Total current financial assets (liabilities), gross basis				$(61,110)
(b) Total noncurrent financial assets (liabilities), gross basis				(5,723)
Net financial assets (liabilities)				$(66,833)

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value at December 31, 2008
		(In thousands)		
Assets(1)				
Current:(a)				
Commodity derivative price swap contracts	$—	$ 64,162	$ —	$ 64,162
Commodity derivative price collar contracts	—	—	49,562	49,562
	—	64,162	49,562	113,724
Noncurrent:(b)				
Commodity derivative price swap contracts	—	60,995	—	60,995
Interest rate derivative swap contracts	—	678	—	678
	—	61,673	—	61,673
Liabilities(1)				
Current:(a)				
Commodity derivative basis swap contracts	—	(680)	—	(680)
Interest rate derivative swap contracts	—	(1,761)	—	(1,761)
	—	(2,441)	—	(2,441)
Noncurrent:(b)				
Commodity derivative price swap contracts	—	(516)	—	(516)
	—	(516)	—	(516)
Net financial assets (liabilities)	$—	$122,878	$49,562	$172,440
(a) Total current financial assets (liabilities), gross basis				$111,283
(b) Total noncurrent financial assets (liabilities), gross basis				61,157
Net financial assets (liabilities)				$172,440

(1) The fair value of derivative instruments reported in the Company's consolidated balance sheets are subject to netting arrangements and qualify for net presentation. The following table reports the net basis derivative fair values as reported in the consolidated balance sheets at December 31, 2009 and 2008:

	December 31,	
	2009	2008
	(In thousands)	
Consolidated Balance Sheet Classification:		
Current derivative contracts:		
Assets	$ 1,309	$113,149
Liabilities	(62,419)	(1,866)
Net current	$(61,110)	$111,283
Noncurrent derivative contracts:		
Assets	$ 23,614	$ 61,157
Liabilities	(29,337)	—
Net noncurrent	$ (5,723)	$ 61,157

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets — The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs.

The Company periodically reviews its proved oil and natural gas properties that are sensitive to oil and natural gas prices for impairment. Due primarily to downward adjustments to the economically recoverable resource potential associated with declines in commodity prices and well performance, the Company recognized impairment expense of \$11.8 million, \$18.4 million and \$7.3 million for the years ended December 31, 2009, 2008 and 2007, respectively, related to its proved oil and natural gas properties. The following table reports the carrying amounts, estimated fair values and impairment expense of long-lived assets for the years ended December 31, 2009, 2008 and 2007:

	Carrying Amount	Estimated Fair Value	Impairment Expense
		(In thousands)	
Year ended December 31, 2009	\$19,884	\$ 7,687	\$12,197
Year ended December 31, 2008	\$31,792	\$13,375	18,417
Year ended December 31, 2007	\$10,445	\$ 3,178	7,267

Asset Retirement Obligations — The Company estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note E for a summary of changes in AROs.

Measurement information for assets that are measured at fair value on a nonrecurring basis was as follows:

	Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Impairment Loss
	(In thousands)			
Year ended December 31, 2009:				
Impairment of long-lived assets	$—	$—	$ 7,687	$(12,197)
Asset retirement obligations incurred in current period	—	—	2,014	
Year ended December 31, 2008:				
Impairment of long-lived assets	$—	$—	$13,375	$(18,417)
Asset retirement obligations incurred in current period	—	—	8,259	
Year ended December 31, 2007:				
Impairment of long-lived assets	$—	$—	$ 3,178	$ (7,267)
Asset retirement obligations incurred in current period	—	—	471	

Note I. ***Derivative financial instruments***

The Company uses derivative financial contracts to manage exposures to commodity price and interest rate fluctuations. Commodity hedges are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. Interest rate hedges are used to mitigate the cash flow risk associated with rising interest rates. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company also may enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

Currently, the Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its statements of operations. All of the Company's remaining hedges that historically qualified for hedge accounting or were dedesignated from hedge accounting were settled in 2008.

A key requirement for designation of derivative instruments to qualify for hedge accounting is that at both the inception of the hedge and on an ongoing basis, the hedging relationship is expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Generally, the hedging relationship can be considered to be highly effective if there is a high degree of historical correlation between the hedging instrument and the forecasted transaction. For all quarters ended prior to July 1, 2007, prices received for the Company's natural gas were highly correlated with the Inside FERC — El Paso Natural Gas index (the "Index") — the Index referenced in all of the Company's natural gas derivative instruments. However, during the quarter ended September 30, 2007, this historical relationship did not meet the criteria as being highly correlated. Natural gas produced from the Company's New Mexico shelf assets has a substantial component of natural gas liquids. Prices received for natural gas liquids are not highly correlated to the price of natural gas, but are more closely correlated to the price of oil. During the third quarter of 2007, the price of oil and natural gas liquids, and therefore, the prices the Company received for its natural gas (including natural gas liquids) rose substantially and at a significantly higher rate than the corresponding change in the Index. This resulted in a decrease in correlation between the prices received and the Index below the level required for cash flow hedge accounting. According to accounting guidelines, an entity shall discontinue hedge accounting prospectively for an existing hedge if the hedge is no longer highly effective. Hedge accounting must be discontinued regardless of whether the Company believes the hedge will be prospectively highly effective. The hedge must be discontinued during the period the hedges became ineffective. As a result, any changes in fair value must be recorded in earnings. Because the natural gas and natural gas liquids prices fluctuate at different rates over time, the loss of effectiveness does not relate to any single date.

During the three months ended June 30, 2007, the Company determined that all of its natural gas commodity contracts no longer qualified as hedges for the reason stated in the above paragraph. These contracts are referred to as "dedesignated hedges."

Therefore, June 30, 2007, was considered the last date the Company's natural gas hedges were highly effective, and the Company discontinued hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges are recorded each period to earnings. Effective portions of dedesignated hedges, previously recorded in AOCI at June 30, 2007, remain in AOCI and are being reclassified into earnings under natural gas revenues, during the periods which the hedged forecasted transaction affects earnings.

New commodity derivative contracts in 2009. During the year ended December 31, 2009, the Company entered into additional commodity derivative contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts for the year ended December 31, 2009. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price collar	600,000	$45.00 - $49.00(a)	3/1/09 - 5/31/09
Price swap	960,000	$59.44(a)	7/1/09 - 12/31/09
Price swap	273,000	$67.50(a)	8/1/09 - 12/31/09
Price swap	3,847,000	$65.81(a)	1/1/10 - 12/31/10
Price swap	2,601,000	$71.66(a)	1/1/11 - 12/31/11
Natural gas (volumes in MMBtus):			
Price collar	1,500,000	$5.00 - $5.81(b)	10/1/09 - 12/31/09
Price collar	1,500,000	$5.00 - $5.81(b)	1/1/10 - 3/31/10
Price collar	3,000,000	$5.25 - $5.75(b)	4/1/10 - 9/30/10
Price collar	1,500,000	$6.00 - $6.80(b)	10/1/10 - 12/31/10
Price collar	1,500,000	$6.00 - $6.80(b)	1/1/11 - 3/31/11
Price swap	3,000,000	$4.31(b)	4/1/09 - 9/30/09
Price swap	1,050,000	$4.66(b)	7/1/09 - 12/31/09
Price swap	8,314,000	$6.12(b)	1/1/10 - 12/31/10
Price swap	300,000	$7.29(b)	1/1/11 - 3/31/11
Price swap	5,400,000	$6.96(b)	4/1/11 - 12/31/11
Basis swap	600,000	$0.79(c)	7/1/09 - 9/30/09
Basis swap	450,000	$0.89(c)	10/1/09 - 12/31/09
Basis swap	8,400,000	$0.85(c)	1/1/10 - 12/31/10
Basis swap	1,800,000	$0.87(c)	1/1/11 - 3/31/11
Basis swap	5,400,000	$0.76(c)	4/1/11 - 12/31/11

(a) The index prices for the oil price swaps and collars are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index prices for the natural gas price swaps and collars are based on the NYMEX-Henry Hub last trading day futures price.

(c) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

Commodity derivative contracts at December 31, 2009. The following table sets forth the Company's outstanding derivative contracts at December 31, 2009. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps:(a)					
2010:					
Volume (Bbl)	1,272,436	1,152,436	1,064,436	999,436	4,488,744
Price per Bbl	$ 69.84	$ 69.72	$ 69.69	$ 69.68	$ 69.74
2011:					
Volume (Bbl)	844,436	805,436	770,436	738,436	3,158,744
Price per Bbl	$ 77.24	$ 77.44	$ 77.65	$ 77.85	$ 77.53
2012:					
Volume (Bbl)	126,000	126,000	126,000	126,000	504,000
Price per Bbl	$ 127.80	$ 127.80	$ 127.80	$ 127.80	$ 127.80
Natural Gas Swaps:(b)					
2010:					
Volume (MMBtu)	2,449,000	2,158,000	1,938,000	1,769,000	8,314,000
Price per MMBtu	$ 6.11	$ 6.12	$ 6.13	$ 6.14	$ 6.12
2011:					
Volume (MMBtu)	300,000	1,800,000	1,800,000	1,800,000	5,700,000
Price per MMBtu	$ 7.29	$ 6.96	$ 6.96	$ 6.96	$ 6.98
Natural Gas Collars:(b)					
2010:					
Volume (MMBtu)	1,500,000	1,500,000	1,500,000	1,500,000	6,000,000
Price per MMBtu	$5.00 - $5.81	$5.25 - $5.75	$5.25 - $5.75	$6.00 - $6.80	$5.38 - $6.03
2011:					
Volume (MMBtu)	1,500,000	—	—	—	1,500,000
Price per MMBtu	$6.00 - $6.80	—	—	—	$6.00 - $6.80
Natural Gas Basis Swaps:(c)					
2010:					
Volume (MMBtu)	2,100,000	2,100,000	2,100,000	2,100,000	8,400,000
Price per MMBtu	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 0.85
2011:					
Volume (MMBtu)	1,800,000	1,800,000	1,800,000	1,800,000	7,200,000
Price per MMBtu	$ 0.87	$ 0.76	$ 0.76	$ 0.76	$ 0.79

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index prices for the natural gas price swaps and collars are based on the NYMEX-Henry Hub last trading day futures price.

(c) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

Interest rate derivative contracts. During 2008, the Company entered into interest rate derivative contracts to hedge a portion of its future interest rate exposure. The Company hedged its LIBOR interest rate on the Company's bank debt by fixing the rate at 1.90 percent for three years beginning in May of 2009 on $300 million of the Company's bank debt. The interest rate derivative contracts were not designated as cash flow hedges.

The Company's reported oil and natural gas revenue includes the effects of oil quality and Btu content, gathering and transportation costs, natural gas processing and shrinkage, and the net effect of the commodity hedges that qualified for cash flow hedge accounting. The following table summarizes the gains and losses reported in earnings related to the commodity and interest rate derivative instruments and the net change in AOCI for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Increase (decrease) in oil and natural gas revenue from derivative activity:			
Cash payments on cash flow hedges in oil sales	$ —	$ (30,591)	$(11,091)
Cash receipts from cash flow hedges in natural gas sales	—	—	188
Dedesignated cash flow hedges reclassified from AOCI in natural gas sales	—	(696)	1,103
Total decrease in oil and natural gas revenue from derivative activity	$ —	$ (31,287)	$ (9,800)
Gain (loss) on derivatives not designated as hedges:			
Mark-to-market gain (loss):			
Commodity derivatives:			
Oil	$(229,896)	$253,960	$(22,988)
Natural gas	(7,959)	3,347	899
Interest rate derivatives	(1,418)	(1,083)	—
Cash (payments on) receipts from derivatives not designated as hedges:			
Commodity derivatives:			
Oil	74,796	(7,780)	—
Natural gas	10,955	1,426	1,815
Interest rate derivatives	(3,335)	—	—
Total gain (loss) on derivatives not designated as hedges	$(156,857)	$249,870	$(20,274)
Gain (loss) from ineffective portion of cash flow hedges	$ —	$ 1,336	$ (821)

	Years Ended December 31, 2009	2008	2007
		(In thousands)	
Accumulated other comprehensive income (loss):			
Cash flow hedges:			
Mark-to-market gain (loss) of cash flow hedges	$ —	$ (7,985)	$(33,783)
Reclassification adjustment of losses to earnings	—	30,591	10,903
Net AOCI upon dedesignation at June 30, 2007	—	—	(407)
Net change, before income taxes	—	22,606	(23,287)
Income tax effect	—	(8,835)	9,102
Net change, net of income taxes	$ —	$ 13,771	$(14,185)
Dedesignated cash flow hedges:			
Net AOCI upon dedesignation at June 30, 2007	$ —	$ —	$ 407
Reclassification adjustment of (gains) losses to earnings	—	696	(1,103)
Income tax effect	—	(272)	272
Net change, net of income taxes	$ —	$ 424	$ (424)

All of the Company's commodity derivative contracts at December 31, 2009 are expected to settle by December 31, 2011. All the Company's commodity derivative contracts previously accounted for as cash flow hedges and dedesignated as hedges were settled on December 31, 2008.

Post-2009 commodity derivative contracts. After December 31, 2009 and through February 24, 2010, the Company entered into the following oil and natural gas price swaps to hedge an additional portion of its estimated future production:

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price swap	670,000	$83.72(a)	1/1/10 - 12/31/10
Price swap	195,000	$76.85(a)	3/1/10 - 12/31/10
Price swap	792,000	$81.77(a)	1/1/11 - 12/31/11
Price swap	168,000	$89.00(a)	1/1/12 - 12/31/12
Natural gas (volumes in MMBtus):			
Price swap	418,000	$5.99(b)	2/1/10 - 12/31/10
Price swap	1,250,000	$5.55(b)	3/1/10 - 12/31/10
Price swap	5,076,000	$6.14(b)	1/1/11 - 12/31/11
Price swap	300,000	$6.54(b)	1/1/12 - 12/31/12

(a) The index price for the oil price swap is based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index prices for the natural gas price swaps are based on the NYMEX-Henry Hub last trading day futures price.

Note J. ***Debt***

The Company's debt consists of the following:

	December 31, 2009	December 31, 2008
	(In thousands)	
Credit facility	$550,000	$630,000
8.625% unsecured senior notes due 2017	300,000	—
Less: unamortized original issue discount	(4,164)	—
Less: current portion	—	—
Total long-term debt	$845,836	$630,000

Credit facility. The Company's credit facility, as amended, has a maturity date of July 31, 2013 (the "Credit Facility"). At December 31, 2009, the Company had letters of credit outstanding under the Credit Facility of approximately $25,000 and its availability to borrow additional funds was approximately $405.9 million. The Company obtained a waiver from lenders representing 95.4 percent of the commitments under the Credit Facility in conjunction with the offering of the Senior Notes, described below, to not reduce the borrowing base as required by the Credit Facility; as a result, the Company's borrowing base was reduced to $955.9 million from $960 million. In October 2009, the lenders reaffirmed the Company's $955.9 million borrowing base under the Credit Facility until the next scheduled borrowing base redetermination in April 2010. Between scheduled borrowing base redeterminations, the Company and, if requested by 66⅔ percent of the lenders, the lenders, may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Company's option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.25 percent at December 31, 2009) or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). At December 31, 2009, the interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 200 to 300 basis points and 112.5 to 212.5 basis points, respectively, per annum depending on the debt balance outstanding. At December 31, 2009, the Company pays commitment fees on the unused portion of the available borrowing base of 50 basis points per annum.

The Credit Facility also includes a same-day advance facility under which the Company may borrow funds from the administrative agent. Same-day advances cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin.

The Company's obligations under the Credit Facility are secured by a first lien on substantially all of the Company's oil and natural gas properties. In addition, all of the Company's subsidiaries are guarantors and all general partner, limited partner and membership interests in the Company's subsidiaries owned by the Company have been pledged to secure borrowings under the Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios, including (i) a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses to be no greater than 4.0 to 1.0, and (ii) a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including the unfunded amounts under the Credit Facility, to be no less than 1.0 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to mergers, combinations and dispositions of assets; and (d) restrictions on the payment of cash dividends. At December 31, 2009, the Company was in compliance with its covenants under the Credit Facility.

8.625% unsecured senior notes. On September 18, 2009, the Company completed its public offering of $300 million aggregate principal amount of 8.625% senior notes due 2017 (the "Senior Notes") at 98.578 percent of par. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of the Company's subsidiaries.

The Senior Notes will mature on October 1, 2017, and interest is payable on the Senior Notes each April 1 and October 1, commencing on April 1, 2010. The Company received net proceeds of $288.2 million (net of related estimated offering costs), which were used to repay a portion of the outstanding borrowings under the Credit Facility.

The Company may redeem some or all of the Senior Notes at any time on or after October 1, 2013 at the redemption prices specified in the indenture governing the Senior Notes. The Company may also redeem up to 35 percent of the Senior Notes using all or a portion of the net proceeds of certain public sales of equity interests completed before October 1, 2012 at a redemption price as specified in the indenture. If the Company sells certain assets or experiences specific kinds of change of control, each as described in the indenture, each holder of the Senior Notes will have the right to require the Company to repurchase the Senior Notes at a purchase price described in the indenture plus accrued and unpaid interest, if any, to the date of repurchase.

The Senior Notes are the Company's senior unsecured obligations, and rank equally in right of payment with all of the Company's existing and future senior debt, and rank senior in right of payment to all of the Company's future subordinated debt. The Senior Notes are structurally subordinated to all of the Company's existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

Future interest expense from the original issue discount at December 31, 2009 is as follows:

	(In thousands)
2010	$ 384
2011	421
2012	462
2013	508
2014	558
Thereafter	1,831
Total	$4,164

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2009 are as follows:

	(In thousands)
2010	$ —
2011	—
2012	—
2013	550,000
2014 and thereafter	300,000
Total	$850,000

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash payments for interest	$14,862	$27,747	$41,036
Amortization of original issue discount	102	58	98
Amortization of deferred loan origination costs	3,635	2,157	1,338
Write-off of deferred loan origination costs and original issue discount	57	1,547	2,631
Net changes in accruals	9,702	(1,237)	(6,414)
Interest costs incurred	28,358	30,272	38,689
Less: capitalized interest	(66)	(1,233)	(2,647)
Total interest expense	$28,292	$29,039	$36,042

Note K. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately $2.0 million.

Indemnifications. The Company has agreed to indemnify its directors and officers, with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a quarter-by-quarter basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Acquisition commitments. In connection with the acquisition of the Henry Entities, the Company agreed to pay certain employees, who were formerly employed by the Henry Entities, bonuses of approximately $11.0 million in the aggregate at each of the first and second anniversaries of the closing of the acquisition, respectively. Except as described below, these employees must remain employed with the Company to receive the bonus. A former Henry Entities employee who is otherwise entitled to a full bonus will receive the full bonus (i) if the Company terminates the employee without cause, (ii) upon the death or disability of such employee or (iii) upon a change in control of the Company. If any such employee resigns or is terminated for cause, the employee will not receive the bonus and, subject to certain conditions, the Company will be required to reimburse the sellers in the acquisition of the Henry Entities 65 percent of the bonus amount not paid to the employee. The Company will reflect the bonus amounts to be paid to these employees as a period cost, which will be included in the Company's results of operations over the period earned. Amounts that ultimately are determined to be paid to the sellers will be treated as a "contingent purchase price" and reflected as an adjustment to the purchase price. During the years ended December 31, 2009 and 2008, the Company recognized $10.1 million and $4.3 million, respectively, of this obligation in its results of operations, and $0.2 million and $0.7 million as contingent purchase price.

Daywork commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company's future drilling commitments at December 31, 2009:

	Payments Due by Period				
	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
	(In thousands)				
Daywork drilling contracts with related parties(a)	$1,000	$1,000	$—	$—	$—
Daywork drilling contracts assumed in the Henry Properties acquisition(b)	781	781	—	—	—
Total contractual drilling commitments	$1,781	$1,781	$—	$—	$—

(a) Consists of daywork drilling contracts with Silver Oak Drilling, LLC, an affiliate of Chase Oil Corporation.

(b) A major oil and natural gas company which owns an interest in the wells being drilled and the Company are parties to these contracts. Only the Company's 25% share of the contract obligation has been reflected above.

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2009, 2008 and 2007 were approximately $2.3 million, $1.3 million and $288,000, respectively.

Future minimum lease commitments under non-cancellable operating leases at December 31, 2009 are as follows:

	(In thousands)
2010	$ 2,291
2011	1,734
2012	1,299
2013	1,170
2014 and thereafter	3,518
Total	$10,012

Note L. *Income taxes*

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Management monitors Company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs") and other deferred tax attributes in the United States, state, and local tax jurisdictions will be utilized prior to their expiration. At December 31, 2009 and 2008, the Company had no valuation allowances related to its deferred tax assets.

At December 31, 2009, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 through 2009 remain subject to examination by the major tax jurisdictions.

The Company's provision for income taxes differed from the U.S. statutory rate of 35 percent primarily due to state income taxes and non-deductible expenses and changes in tax rates. The effective income tax rate for the years ended December 31, 2009, 2008 and 2007 was 67.9 percent, 36.8 percent and 38.7 percent, respectively.

Income tax provision. The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Income (loss) from operations	$(20,732)	$162,085	$ 16,019
Changes in stockholders' equity:			
Net deferred hedge gains (losses)	—	(3,121)	(13,204)
Net settlement losses included in earnings	—	12,228	3,830
Excess tax benefits related to stock-based compensation	(5,212)	(3,614)	—
	$(25,944)	$167,578	$ 6,645

The Company's income tax provision (benefit) attributable to income from operations consisted of the following for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Current:			
U.S. federal	$ 8,434	$ 8,080	$ 1,902
U.S. state and local	1,753	521	401
	10,187	8,601	2,303
Deferred:			
U.S. federal	(17,647)	141,668	10,069
U.S. state and local	(13,272)	11,816	3,647
	(30,919)	153,484	13,716
	$(20,732)	$162,085	$16,019

The reconciliation between the tax expense (benefit) computed by multiplying pretax income (loss) by the U.S. federal statutory rate and the reported amounts of income tax expense (benefit) is as follows:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Income (loss) at U.S. federal statutory rate	$(10,687)	$154,276	$14,483
State income taxes (net of federal tax effect)	(899)	13,372	2,631
Revision of previous tax estimates	(1,559)	—	—
Statutory depletion	(581)	—	(613)
Change in effective statutory state income tax rate	(6,556)	(5,671)	—
Nondeductible expense & other	(450)	108	(482)
Income tax expense (benefit)	$(20,732)	$162,085	$16,019

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

	December 31, 2009	December 31, 2008
	(In thousands)	
Deferred tax asset:		
Stock-based compensation	$ 6,652	$ 5,569
Derivative instruments	25,186	—
Statutory depletion carryover	—	1,635
Federal tax credit carryovers	3,495	8,525
Asset retirement obligation	8,575	6,403
Accrued liabilities	4,180	1,107
Allowance for bad debt	918	2,767
Other	94	348
Total deferred tax assets	49,100	26,354
Deferred tax liability:		
Oil and natural gas properties, principally due to differences in basis and depletion and the deduction of intangible drilling costs for tax purposes	(609,268)	(557,011)
Intangible asset — operating rights	(13,763)	(14,387)
Derivative instruments	—	(65,689)
Other	(71)	(235)
Total deferred tax liabilities	(623,102)	(637,322)
Net deferred tax liability	$(574,002)	$(610,968)

Note M. *Major customers and derivative counterparties*

Sales to major customers. The Company's share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for ten percent or more of the consolidated oil and natural gas revenues, including the results of commodity hedges, during the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31, 2009	2008	2007
Navajo Refining Company, L.P.	38%	59%	60%
DCP Midstream LP	13%	18%	23%

At December 31, 2009, the Company had receivables from Navajo Refining Company, L.P. and DCP Midstream LP of $21.2 million and $8.0 million, respectively, which are reflected in Accounts receivable — oil and natural gas in the accompanying consolidated balance sheet.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. The Company's credit facility agreements require that the senior unsecured debt ratings of the Company's derivative counterparties be not less than either A- by Standard & Poor's Rating Group rating system or A3 by Moody's Investors Service, Inc. rating system. At December 31, 2009 and 2008, the counterparties with whom the Company had outstanding derivative contracts met or exceeded the required ratings. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, management believes the associated credit risk is mitigated by the Company's credit risk policies and procedures and by the credit rating requirements of the Company's credit facility agreements.

Note N. ***Related party transactions***

Consulting Agreement. On June 30, 2009, Steven L. Beal, the Company's President and Chief Operating Officer, retired from such positions. Mr. Beal was recently re-elected to the Company's Board of Directors and continues to serve as a member of the Company's Board of Directors. On June 9, 2009, the Company entered into a consulting agreement (the "Consulting Agreement") with Mr. Beal, under which Mr. Beal began serving as a consultant to the Company on July 1, 2009. Either the Company or Mr. Beal may terminate the consulting relationship at any time by giving ninety days written notice to the other party; however, the Company may terminate the relationship immediately for cause. During the term of the consulting relationship, Mr. Beal will receive a consulting fee of $20,000 per month and a monthly reimbursement for his medical and dental coverage costs. If Mr. Beal dies during the term of the Consulting Agreement, his estate will receive a $60,000 lump sum payment. As part of the consulting agreement, certain of Mr. Beal's stock-based awards were modified to permit vesting and exercise under the original terms of the stock-based awards as if Mr. Beal were still an employee of the Company while he is performing consulting services for the Company.

Contract Operator Agreement and Transition Services Agreement. On February 27, 2006, the Company signed a Contract Operator Agreement with Mack Energy Corporation ("MEC"), an affiliate of the Chase Group, whereby the Company engaged MEC as its contract operator to provide certain services with respect to the oil and natural gas properties contributed to us by the Chase Group in 2006 (which we refer to collectively as the "Chase Group Properties"). The initial term of the Contract Operator Agreement was five years commencing on March 1, 2006 and ending on February 28, 2011. The Company and MEC entered into a Transition Services Agreement on April 23, 2007, which terminated the Contract Operator Agreement and under which MEC continued to provide certain field level operating services on the Chase Group Properties. The Transition Services Agreement was terminated automatically on August 7, 2007 upon the Company's completion of the Company's initial public offering. Upon termination of such agreement, the Company's employees along with third party contractors assumed the operation of the subject properties.

The Company incurred charges from MEC, its affiliate remains a stockholder of the Company, of approximately $1.5 million and $1.9 million for the years ended December 31, 2009 and 2008, respectively, in the ordinary course of business. The Company incurred charges from MEC of approximately $18.2 million during 2007 for services rendered under the Contract Operator Agreement and Transition Services Agreement through the termination dates of the respective agreements.

The Company had $87,000 in outstanding receivables due from MEC at December 31, 2009, which are reflected in accounts receivable — related parties in the accompanying consolidated balance sheet and no outstanding receivables due from MEC at December 31, 2008. The Company had $9,000 in outstanding payables to MEC at December 31, 2009, which are reflected in accounts payable — related parties in the accompanying consolidated balance sheet and no outstanding payables to MEC at December 31, 2008.

Saltwater disposal services agreement. Among the assets the Company acquired from Chase Oil, its affiliate remains a stockholder of the Company, is an undivided interest in a saltwater gathering and disposal system, which is owned and maintained under a written agreement among the Company and Chase Oil and certain of its affiliates, and under which the Company as operator gathers and disposes of produced water. The system is owned jointly by the Company and Chase Oil and its affiliates in undivided ownership percentages, which are annually redetermined as of January 1 on the basis of each party's percentage contribution of the total volume of produced water disposed of through the system during the prior calendar year. As of January 1, 2009, the Company owned 95.4 percent of the system and Chase Oil and its affiliates owned 4.6 percent.

Other related party transactions. The Company also has engaged in transactions with certain other affiliates of the Chase Group, its affiliate remains a stockholder of the Company, including a drilling contractor, an oilfield services company, a supply company, a drilling fluids supply company, a pipe and tubing supplier, a fixed base operator of aircraft services and a software company.

The Company incurred charges from these related party vendors of approximately $32.8 million, $23.2 million and $43.8 million for the years ended December 31, 2009, 2008 and 2007, respectively, for services rendered.

The Company had no outstanding invoices payable to the other related party vendors identified above at December 31, 2009, and approximately $21,000 in outstanding payables at December 31, 2008, which are reflected in accounts payable — related parties in the accompanying consolidated balance sheet.

Overriding royalty and royalty interests. Certain members of the Chase Group, its affiliate remains a stockholder of the Company, own overriding royalty interests in certain of the Chase Group Properties. The amount paid attributable to such interests was approximately $1.3 million, $3.1 million and $2.4 million for the years ended December 31, 2009, 2008 and 2007, respectively. The Company owed royalty payments of approximately $255,000 and $146,000 to these members of the Chase Group at December 31, 2009 and 2008, respectively. These amounts are reflected in accounts payable — related parties in the accompanying consolidated balance sheets.

Royalties are paid on certain properties located in Andrews County, Texas to a partnership of which one of the Company's directors is the General Partner, and who also owns a 3.5 percent partnership interest. The Company paid approximately $134,000, $332,000 and $205,000 for the years ended December 31, 2009, 2008 and 2007, respectively. The Company owed this partnership royalty payments of approximately $12,000 and $13,000 at December 31, 2009 and 2008, respectively. These amounts are reflected in accounts payable — related parties in the accompanying consolidated balance sheets.

Working interests owned by employees. As part of the Henry Properties acquisition, the Company purchased oil and natural gas properties in which employees owned a working interest. The following table summarizes the Company's activities with these employees:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Revenues distributed to employees	$100	$155	$—
Joint interest payments received from employees	$141	$635	$—

	December 31,	
	2009	2008
Amounts included in accounts receivable — related parties	$128	$300
Amounts included in accounts payable — related parties	$ 13	$ —

Note O. *Net income (loss) per share*

Basic net income (loss) per share is computed by dividing net income (loss) applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period.

The computation of diluted income (loss) per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income (loss) were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. These amounts include unexercised capital options, stock options and restricted stock (as issued under the Plan and described in Note G). Potentially dilutive effects are calculated using the treasury stock method.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Weighted average common shares outstanding:			
Basic	84,912	79,206	64,316
Dilutive capital options	—	6	1,001
Dilutive common stock options	—	1,134	901
Dilutive restricted stock	—	241	91
Diluted	84,912	80,587	66,309

In 2009, the Company incurred a net loss; accordingly all potentially dilutive securities were anti-dilutive and not included in determining diluted net loss per share. In 2009, the anti-dilutive securities included (i) common stock options to purchase 2,156,503 shares and (ii) 497,257 shares of restricted stock. In 2008 and 2007, since the Company had net income applicable to common shareholders, the effects of all potentially dilutive securities including capital options, incentive stock options and unvested restricted stock were considered in the computation of diluted earnings per share. Because the exercise prices of certain incentive stock options were greater than the average market price of the common shares and would be anti-dilutive, incentive stock options to purchase 313,354 shares and 366,250 of common stock for the years ended December 31, 2008 and 2007, respectively, were outstanding but not included in the computations of diluted income per share from continuing operations. Also excluded from the computation of diluted income per share for the year ended December 31, 2008, were 56,086 shares of restricted stock because the effect would be anti-dilutive.

Note P. *Other current liabilities*

The following table provides the components of the Company's other current liabilities at December 31, 2009 and 2008:

	December 31,	
	2009	2008
	(In thousands)	
Other current liabilities:		
Accrued production costs	$24,128	$15,489
Payroll related matters	14,490	11,290
Accrued interest	10,055	353
Asset retirement obligations	3,262	2,611
Other	8,160	8,314
Other current liabilities	$60,095	$38,057

Note Q. *Subsidiary guarantors*

All of the Company's wholly-owned subsidiaries have fully and unconditionally guaranteed the Senior Notes of the Company (see Note J). In accordance with practices accepted by the SEC, the Company has prepared Consolidating Condensed Financial Statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. The following Consolidating Condensed Balance Sheets at December 31, 2009 and 2008, and Consolidating Statements of Operations and Consolidating Condensed Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007, present financial information for Concho Resources Inc. as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc. as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors are not restricted from making distributions to the Company.

Consolidating Condensed Balance Sheet
December 31, 2009

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
		(In thousands)		
ASSETS				
Accounts receivable — related parties	$2,715,307	$1,738,382	$(4,453,473)	$ 216
Other current assets	33,561	183,481	—	217,042
Total oil and natural gas properties, net	—	2,840,583	—	2,840,583
Total property and equipment, net	—	15,706	—	15,706
Investment in subsidiaries	876,154	—	(876,154)	—
Total other long-term assets	44,291	53,247	—	97,538
Total assets	$3,669,313	$4,831,399	$(5,329,627)	$3,171,085
LIABILITIES AND EQUITY				
Accounts payable — related parties	$ 790,251	$3,663,513	$(4,453,473)	$ 291
Other current liabilities	68,706	268,017	—	336,723
Other long-term liabilities	629,092	23,715	—	652,807
Long-term debt	845,836	—	—	845,836
Equity	1,335,428	876,154	(876,154)	1,335,428
Total liabilities and equity	$3,669,313	$4,831,399	$(5,329,627)	$3,171,085

Consolidating Condensed Balance Sheet
December 31, 2008

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
		(In thousands)		
ASSETS				
Accounts receivable — related parties	$2,500,186	$1,432,829	$(3,932,701)	$ 314
Other current assets	120,406	158,063	—	278,469
Total oil and natural gas properties, net	—	2,386,584	—	2,386,584
Total property and equipment, net	—	14,820	—	14,820
Investment in subsidiaries	734,969	—	(734,969)	—
Total other long-term assets	73,538	61,478	—	135,016
Total assets	$3,429,099	$4,053,774	$(4,667,670)	$2,815,203
LIABILITIES AND EQUITY				
Accounts payable — related parties	$ 860,758	$3,072,255	$(3,932,701)	$ 312
Other current liabilities	39,424	231,082	—	270,506
Other long-term liabilities	573,763	15,468	—	589,231
Long-term debt	630,000	—	—	630,000
Equity	1,325,154	734,969	(734,969)	1,325,154
Total liabilities and equity	$3,429,099	$4,053,774	$(4,667,670)	$2,815,203

Consolidating Condensed Statement of Operations
For the Year Ended December 31, 2009

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
	(In thousands)			
Total operating revenues	$ —	$ 544,447	$ —	$ 544,447
Total operating costs and expenses	(143,427)	(402,848)	—	(546,275)
Income (loss) from operations	(143,427)	141,599	—	(1,828)
Interest expense	(28,292)	—	—	(28,292)
Other, net	(141,185)	(414)	141,185	(414)
Income (loss) before income taxes	(312,904)	141,185	141,185	(30,534)
Income tax benefit	20,732	—	—	20,732
Net income (loss)	$(292,172)	$ 141,185	$141,185	$ (9,802)

Consolidating Condensed Statement of Operations
For the Year Ended December 31, 2008

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
	(In thousands)			
Total operating revenues	$ (31,287)	$ 565,076	$ —	$ 533,789
Total operating costs and expenses	177,384	(242,779)	—	(65,395)
Income from operations	146,097	322,297	—	468,394
Interest expense	(29,039)	—	—	(29,039)
Other, net	323,729	1,432	(323,729)	1,432
Income before income taxes	440,787	323,729	(323,729)	440,787
Income tax expense	(162,085)	—	—	(162,085)
Net income	$ 278,702	$ 323,729	$(323,729)	$ 278,702

Consolidating Condensed Statement of Operations
For the Year Ended December 31, 2007

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
	(In thousands)			
Total operating revenues	$ (2,968)	$ 297,301	$ —	$ 294,333
Total operating costs and expenses	(22,472)	(195,924)	—	(218,396)
Income (loss) from operations	(25,440)	101,377	—	75,937
Interest expense	(36,042)	—	—	(36,042)
Other, net	102,861	1,174	(102,551)	1,484
Income before income taxes	41,379	102,551	(102,551)	41,379
Income tax expense	(16,019)	—	—	(16,019)
Net income	$ 25,360	$ 102,551	$(102,551)	$ 25,360
Preferred stock dividends	(45)	—	—	(45)
Net income applicable to common shareholders	$ 25,315	$ 102,551	$(102,551)	$ 25,315

Consolidating Condensed Statement of Cash Flows For the Year Ended December 31, 2009

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
		(In thousands)		
Net cash flows provided by (used in) operating activities	$(295,240)	$ 654,786	$—	$ 359,546
Net cash flows provided by (used in) investing activities	77,185	(663,333)	—	(586,148)
Net cash flows provided by (used in) financing activities	218,103	(6,019)	—	212,084
Net increase (decrease) in cash and cash equivalents	48	(14,566)	—	(14,518)
Cash and cash equivalents at beginning of year	—	17,752	—	17,752
Cash and cash equivalents at end of year	$ 48	$ 3,186	$—	$ 3,234

Consolidating Condensed Statement of Cash Flows For the Year Ended December 31, 2008

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
		(In thousands)		
Net cash flows provided by (used in) operating activities	$(532,919)	$ 924,316	$—	$ 391,397
Net cash flows used in investing activities	(5,386)	(940,664)	—	(946,050)
Net cash flows provided by financing activities	538,198	3,783	—	541,981
Net decrease in cash and cash equivalents	(107)	(12,565)	—	(12,672)
Cash and cash equivalents at beginning of year	107	30,317	—	30,424
Cash and cash equivalents at end of year	$ —	$ 17,752	$—	$ 17,752

Consolidating Condensed Statement of Cash Flows For the Year Ended December 31, 2007

	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
		(In thousands)		
Net cash flows provided by (used in) operating activities	$(15,094)	$ 184,863	$—	$ 169,769
Net cash flows provided by (used in) investing activities	631	(160,984)	—	(160,353)
Net cash flows provided by financing activities	14,235	5,651	—	19,886
Net increase (decrease) in cash and cash equivalents	(228)	29,530	—	29,302
Cash and cash equivalents at beginning of year	335	787	—	1,122
Cash and cash equivalents at end of year	$ 107	$ 30,317	$—	$ 30,424

Note R. ***Subsequent events***

Equity issuance. On February 1, 2010, the Company issued 5,347,500 shares of its common stock at $42.75 per share. After deducting underwriting discounts of approximately $9.1 million and estimated transaction costs, the Company received net proceeds of approximately $219.2 million. The net proceeds from this offering were used to repay a portion of the borrowings under the credit facility.

Capitalized Costs

	December 31, 2009	December 31, 2008
	(In thousands)	
Oil and natural gas properties:		
Proved	$3,139,424	$2,316,330
Unproved	218,580	377,244
Less: accumulated depletion	(517,421)	(306,990)
Net capitalized costs for oil and natural gas properties	$2,840,583	$2,386,584

Costs Incurred for Oil and Natural Gas Producing Activities(a)

	Years Ended December 31, 2009	2008	2007
		(In thousands)	
Property acquisition costs:			
Proved	$205,817	$ 597,713	$ —
Unproved	74,692	240,294	7,293
Exploration	134,105	160,174	116,004
Development	265,731	178,842	64,524
Total costs incurred for oil and natural gas properties	$680,345	$1,177,023	$187,821

(a) The costs incurred for oil and natural gas producing activities includes the following amounts of asset retirement obligations:

	Years Ended December 31, 2009	2008	2007
		(In thousands)	
Proved property acquisition costs	$ 488	$ 7,062	$ —
Exploration costs	452	563	(15)
Development costs	5,425	(1,123)	315
Total	$6,365	$ 6,502	$300

Reserve Quantity Information

The following information represents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2009 was based on an unweighted average twelve month average West Texas Intermediate posted price of $57.65 per Bbl for oil and a Henry Hub spot natural gas price of $3.87 per MMBtu for natural gas, see table below. As a result of this change in pricing methodology, direct comparisons of previously-reported reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule has limited and may continue to limit the Company's potential to book additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, the Company may be required to write down our proved undeveloped reserves if we do not drill on those reserves with the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The SEC has not reviewed the Company's or any reporting company's reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of the Company's proved reserves and related estimated discounted future net cash flows at December 31, 2009, included in this report have been prepared based on what the Company and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates the Company might prepare applying more specific SEC interpretive guidance.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of Southeast New Mexico and West Texas. The estimates of 93 percent of the proved reserves at December 31, 2009 are based on reports prepared by Cawley, Gillespie & Associates Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers, with the remaining portion being prepared the Company's internal reserve engineering staff. All of the estimates of the proved reserves at December 31, 2008 and 2007 are based on reports prepared by Cawley, Gillespie & Associates Inc. and Netherland, Sewell & Associates, Inc. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2009, 2008 and 2007. Commodity prices utilized for the reserve estimates were adjusted for location, grade and quality are as follows:

	December 31,		
	2009	2008	2007
Prices utilitzed in the reserve estimates before adjustments:			
Oil per Bbl(a)	$57.65	$41.00	$92.50
Gas per MMBtu(b)	$ 3.87	$ 5.71	$ 6.80

(a) The pricing used to estimate our 2009 reserves was based on a 12-month unweighted average first-day-of-the-month West Texas Intermediate posted price; whereas, the pricing used for 2008 and 2007 was based on year-end West Texas Intermediate posted prices.

(b) The pricing used to estimate our 2009 reserves was based on a 12-month unweighted average first-day-of-the-month Henry Hub spot price; whereas, the pricing used for 2008 and 2007 was based on year-end Henry Hub spot market prices.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2009, 2008 and 2007, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year. Oil and condensate volumes are expressed in MBbls and natural gas volumes are expressed in MMcf.

	2009			2008			2007		
	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Total Proved Reserves:									
Balance, January 1	86,285	305,948	137,275	53,361	225,837	91,000	44,322	200,818	77,792
Purchase of minerals-in-place	13,916	38,096	20,265	20,837	56,022	30,174	105	354	164
Sales of minerals-in-place	(18)	(315)	(71)	—	—	—	(1)	—	(1)
Discoveries and extensions(a)	47,750	109,150	65,942(b)	24,194	73,380	36,424	13,140	48,751	21,265
Revisions of previous estimates	1,421	(14,400)	(977)	(7,521)	(34,323)	(13,242)	(1,191)	(12,022)	(3,195)
Production	(7,336)	(21,568)	(10,931)	(4,586)	(14,968)	(7,081)	(3,014)	(12,064)	(5,025)
Balance, December 31	142,018	416,911	211,503	86,285	305,948	137,275	53,361	225,837	91,000
Proved Developed Reserves:									
January 1	46,661	179,124	76,515	27,617	128,872	49,096	23,443	112,423	42,180
December 31	66,578	222,776	103,707	46,661	179,124	76,515	27,617	128,872	49,096
Proved Undeveloped Reserves:									
January 1	39,624	126,824	60,760	25,744	96,965	41,904	20,879	88,395	35,612
December 31	75,440	194,135	107,796(b)	39,624	126,824	60,760	25,744	96,965	41,904

(a) The 2009, 2008 and 2007 discoveries and extensions included 42,645, 14,533 and 9,601 net MBoe, respectively, related to additions from the Company's infill drilling activities.

(b) Includes additions of 13.6 MMBoe resulting from the adoption of the new SEC rules related to disclosures of oil and natural gas reserves that are effective for fiscal years ending on or after December 31, 2009.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying at December 31, 2009 the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas and at December 31, 2008 and 2007 year-end prices of oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

The following table provides the standardized measure of discounted future net cash flows at December 31, 2009, 2008 and 2007:

	December 31, 2009	December 31, 2008	December 31, 2007
		(In thousands)	
Oil and gas producing activities:			
Future cash inflows	$10,145,876	$ 5,785,109	$ 6,507,955
Future production costs	(2,956,257)	(1,666,380)	(1,517,415)
Future development and abandonment costs(a)	(1,272,695)	(668,005)	(484,140)
Future income tax expense	(1,807,582)	(919,251)	(1,482,633)
	4,109,342	2,531,473	3,023,767
10% annual discount factor	(2,187,313)	(1,332,488)	(1,591,993)
Standardized measure of discounted future net cash flows	$ 1,922,029(b)	$ 1,198,985	$ 1,431,774

(a) Includes $11.7 million, $28.8 million and $19.5 million of undiscounted asset retirement cash inflow estimated at December 31, 2009, 2008 and 2007, respectively, using current estimates of future salvage values less future abandonment costs. See Note E for corresponding information regarding the Company's discounted asset retirement obligations.

(b) Includes $66.4 million resulting from the adoption of the new SEC rules related to determination and disclosures of oil and natural gas reserves that are effective for fiscal years ending on or after December 31, 2009.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Oil and gas producing activities:			
Purchases of minerals-in-place	$ 403,242	$ 1,014,689	$ 4,054
Sales of minerals-in-place	(953)	(24)	(54)
Extensions and discoveries	844,742	426,208	511,519
Net changes in prices and production costs	220,372	(1,622,800)	802,584
Oil and natural gas sales, net of production costs	(436,329)	(442,554)	(249,866)
Changes in future development costs	49,626	74,160	72,441
Revisions of previous quantity estimates	(19,234)	(283,557)	(82,299)
Accretion of discount	162,844	255,660	85,533
Changes in production rates, timing and other	(87,960)	72,850	35,834
Change in present value of future net revenues	1,136,350	(505,368)	1,179,746
Net change in present value of future income taxes	(413,306)	272,579	(458,321)
	723,044	(232,789)	721,425
Balance, beginning of year	1,198,985	1,431,774	710,349
Balance, end of year	$1,922,029	$ 1,198,985	$1,431,774

CONCHO RESOURCES INC.

UNAUDITED SUPPLEMENTARY INFORMATION — (Continued)

Selected Quarterly Financial Results

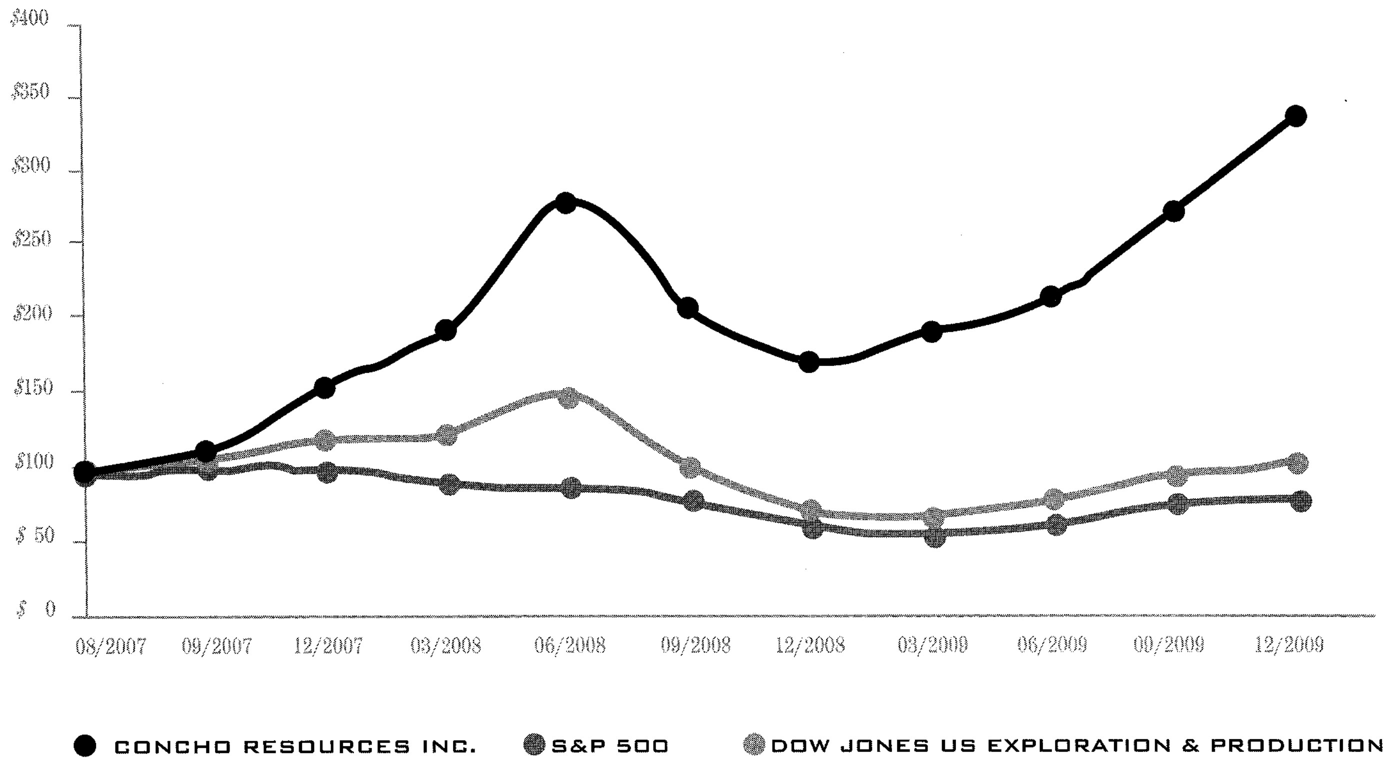
The following table provides selected quarterly financial results for the years ended December 31, 2009 and 2008:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
Year ended December 31, 2009:				
Total operating revenues	$ 86,002	$ 127,332	$153,494	$ 177,619
Operating costs and expenses (excluding loss on derivatives not designated as hedges)	(97,589)	(98,615)	(97,116)	(96,098)
Loss on derivatives not designated as hedges	(5,046)	(81,606)	(7,783)	(62,422)
Income (loss) from operations	$ (16,633)	$ (52,889)	$ 48,595	$ 19,099
Net income (loss)	$ (13,225)	$ (33,218)	$ 19,762	$ 16,879
Net income (loss) per common share — Basic	$ (0.16)	$ (0.39)	$ 0.23	$ 0.20
Net income (loss) per common share — Diluted	$ (0.16)	$ (0.39)	$ 0.23	$ 0.20
Year ended December 31, 2008:				
Total operating revenues	$106,711	$ 137,383	$170,457	$ 119,238
Operating costs and expenses (excluding gain (loss) on derivatives not designated as hedges)	(48,205)	(54,942)	(90,889)	(121,229)
Gain (loss) on derivatives not designated as hedges	(17,178)	(102,456)	163,312	206,192
Income (loss) from operations	$ 41,328	$ (20,015)	$242,880	$ 204,201
Net income (loss)	$ 22,365	$ (14,420)	$141,928	$ 128,829
Net income (loss) per common share — Basic	$ 0.30	$ (0.19)	$ 1.75	$ 1.53
Net income (loss) per common share — Diluted	$ 0.29	$ (0.19)	$ 1.72	$ 1.51

COMPARISON OF 28 MONTH CUMULATIVE TOTAL RETURN*

Among Concho Resources, Inc.,

The S&P 500 Index and The Dow Jones US Exploration & Production Index



*$100 invested on 08/03/2007 in stock & 07/31/2007 in index-including reinvestment of dividends.

EBITDAX RECONCILIATION

	Years ended December 31,			
(In Thousands)	**2009**	**2008**	**2007**	**2006**
NET INCOME (LOSS)	$(9,802)	$278,702	$25,360	$19,668
Exploration and abandonments	10,660	38,468	29,098	5,612
Depreciation, depletion, and amortization	206,143	123,912	76,779	60,722
Accretion of discount on asset retirement obligations	1,058	889	444	287
Impairments of long-lived assets	12,197	18,417	7,267	9,891
Non-cash stock-based compensation	9,040	5,223	3,841	9,144
Ineffective portion of cash flow hedges	-	(1,336)	821	(1,193)
Unrealized (gain) loss on derivatives not designated as hedges	239,273	(256,224)	22,089	-
Interest expense	28,292	29,039	36,042	30,567
Bad debt expense	(1,035)	2,905	-	-
Income tax expense (benefit)	(20,732)	162,085	16,019	14,379
EBITDAX	$475,094	$402,080	$217,760	$149,077

CORPORATE INFORMATION

CORPORATE HEADQUATERS

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New York Stock Exchange under
the symbol, CXO.

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918.877.0800

ANNUAL MEETING

The Annual Meeting for Concho Resources Inc. shareholders will be held in the Wildcatter Room at the Petroleum Club of Midland on June 9, 2010 at 3:00 PM.

FORM 10-K

For an additional copy of the
Annual Report on Form 10-K,
please contact: Concho Resources Inc.
Investor Relations Department
432.683.7443
Email: ir@conchoresources.com

FORWARD-LOOKING STATEMENTS

The foregoing contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included here in that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained here in specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's drilling program, production, derivatives activities, capital expenditure levels and other guidance included in this report. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute our business plan, our ability to replace reserves and efficiently develop and exploit our current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's reports filed with the Securities and Exchange Commission.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

CONCHO

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